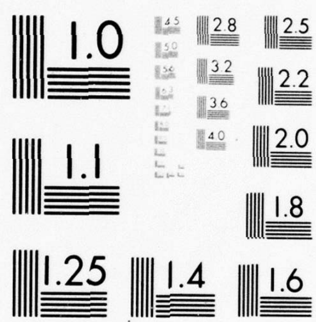
AD-A054 148 INSTITUTE FOR WATER RESOURCES (ARMY) FORT BELVOIR VA F/G 10/2
MCCLELLAN-KERR ARKANSAS RIVER NAVIGATION SYSTEM. HYDROELECTRIC --ETC(U)
DEC 77

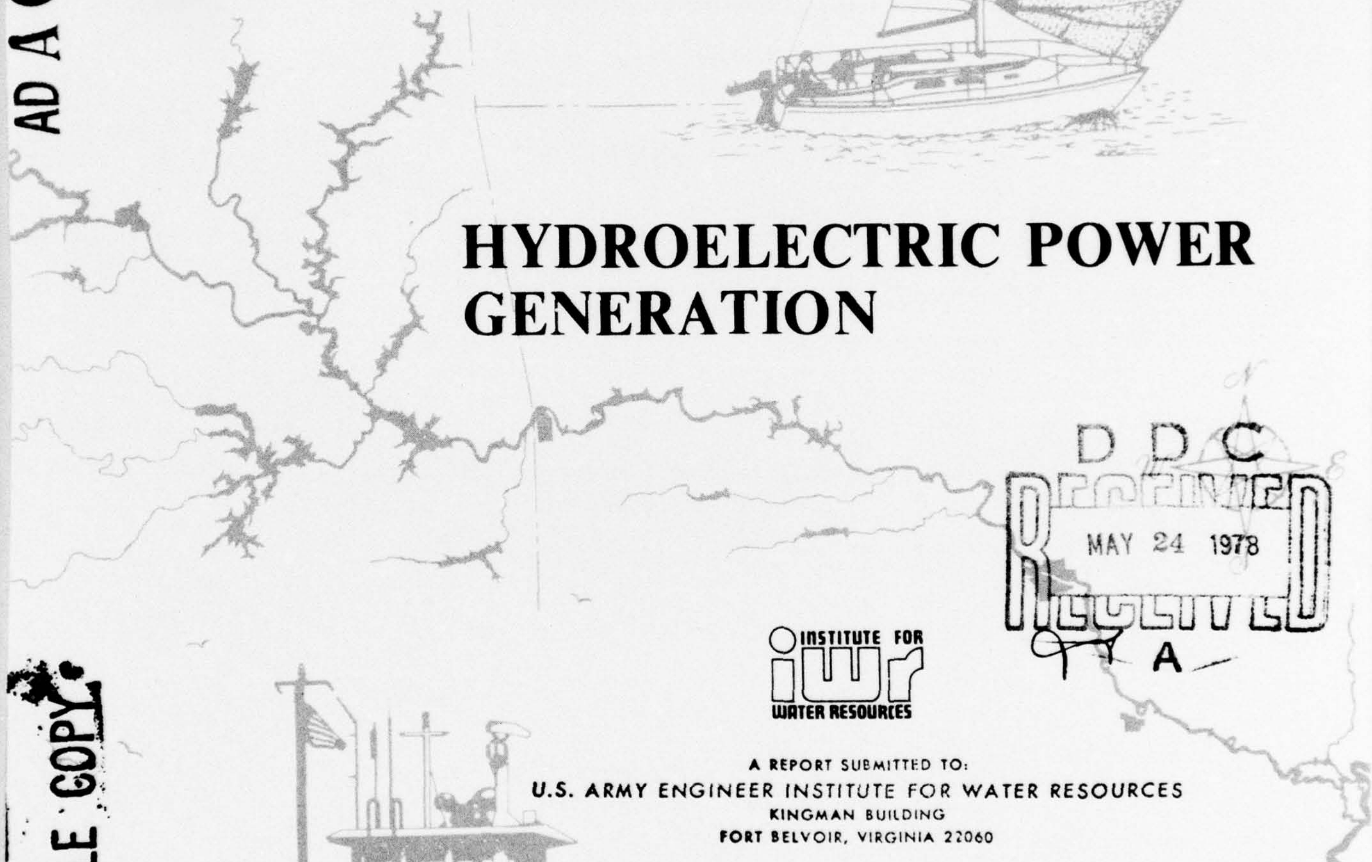
UNCLASSIFIED IWR-RR-77-R4 NL

1 OF 2
AD
A054148



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

McCLELLAN-KERR ARKANSAS RIVER NAVIGATION SYSTEM

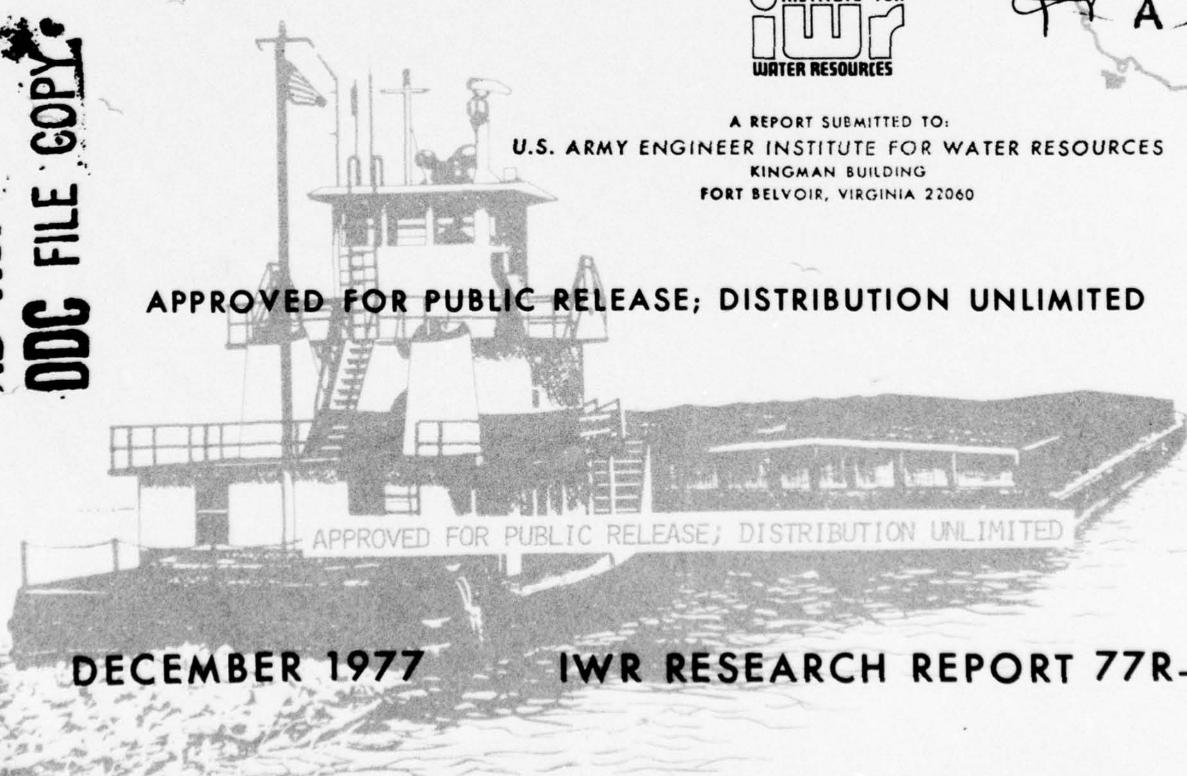


HYDROELECTRIC POWER GENERATION

INSTITUTE FOR WATER RESOURCES

A REPORT SUBMITTED TO:
U.S. ARMY ENGINEER INSTITUTE FOR WATER RESOURCES
KINGMAN BUILDING
FORT BELVOIR, VIRGINIA 22060

APPROVED FOR PUBLIC RELEASE; DISTRIBUTION UNLIMITED



DECEMBER 1977 IWR RESEARCH REPORT 77R-4

McClellan-Kerr Arkansas River

Navigation System

HYDROELECTRIC POWER GENERATION

A Report Submitted to:

U.S. Army Engineer Institute for Water Resources
Kingman Building
Fort Belvoir, Virginia 22060

By:

U.S. Army Engineer Division, Southwestern
Dallas, Texas 75202

DECEMBER 1977

IWR Research Report 77-R4

Copies may be purchased from:

National Technical Information Service
U. S. Department of Commerce
Springfield, Virginia 22151

UNCLASSIFIED

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE		READ INSTRUCTIONS BEFORE COMPLETING FORM
1. REPORT NUMBER (14) IWR-RR IWR Research Report 77-R4	2. GOVT ACCESSION NO.	3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle) (6) McClellan-Kerr Arkansas River Navigation System, HYDROELECTRIC POWER GENERATION.		5. TYPE OF REPORT & PERIOD COVERED (9) Final rept. 6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s) US Army Engr Division, Southwestern Main Tower Building, 1200 Main Street Dallas, Texas 75202		8. CONTRACT OR GRANT NUMBER(s)
9. PERFORMING ORGANIZATION NAME AND ADDRESS US Army Engr Institute for Water Resources Kingman Building Fort Belvoir, Virginia 22060		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS
11. CONTROLLING OFFICE NAME AND ADDRESS	(11)	12. REPORT DATE December 1977 13. NUMBER OF PAGES 110
14. MONITORING AGENCY NAME & ADDRESS (if different from Controlling Office) (12) 122p.		15. SECURITY CLASS. (of this report) Unclassified 15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

Approved for public release; distribution unlimited.

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

18. SUPPLEMENTARY NOTES

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Hydroelectric power, federal power capacity, Southwestern Power Administration, economic benefits, water use, water resources, cost allocation, hydropower marketing, multi-purpose water projects, annual benefits.

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

This report presents an analysis of the hydroelectric generating facilities in the McClellan-Kerr River Project. Installed capacity of the federal installations total 639 megawatts. Economic and financial questions of production and marketing are examined (the power is sold by a federal agency, the Southwestern Power Administration). Due to the rising cost of other fuels, the power benefits are expected to rise from a project justification estimate of $14 million to over $40 million. However, benefits are not as

DD FORM 1 JAN 73 1473 EDITION OF 1 NOV 65 IS OBSOLETE

UNCLASSIFIED

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

405728

1B

high as possible, primarily due to poor marketing practices by the SPA. There are also several problems in the cost allocation formula used to rate the on-going return on investment to the Federal Government for each dam taken individually.

This report is one of a series of impact-studies by the Institute for Water Resources dealing with the McClellan-Kerr Arkansas River Navigation System. All the reports listed below may be purchased from:

National Technical Information Service
U.S. Department of Commerce
Springfield, Virginia 22151

1.) "Recent Developments in the McClellan-Kerr Arkansas River Navigation System Area." IWR Research Report 77-R1

2.) "A Research Strategy for Social Impact Assesment: A Tale of Three Cities." IWR Contract Report 77-R2

3.) "An Application of the Interregional I/O Model for the Study of the Impact of the McClellan-Kerr Arkansas River Multiple Purpose Project." IWR Contract Report 77-2

4.) "Analysis of Expenditures for Outdoor Recreation at the McClellan-Kerr Arkansas River Navigation System." IWR Contract Report 77-4

5.) "Population Change, Migration and Displacement Along the McClellan-Kerr Arkansas River Navigation System." IWR Contract Report 77-5

6.) "McClellan-Kerr Arkansas River Navigation System: Hydroelectric Power Generation." IWR Research Report 77-R4.

7.) "A River, A Region and A Research Problem." IWR Research Report 71-6

8.) "Regional Response Through Port Development: An Economic Case Study on the McClellan-Kerr Arkansas River Project." IWR Contract Report 74-5

9.) "Evaluation of Interregional Input-Output Models for Potential Use in the McClellan-Kerr Arkansas River Multiple Purpose Project Impact Study." IWR Contract Report 74-6

10.) "Discriminant Analysis Applied to Commodity Shipments in the Arkansas River Area." IWR Research Report 74-R2

11.) "An Overview of the Impact Study of the McClellan-Kerr Multiple Purpose Arkansas River System." IWR Research Report 75-R3

FOREWARD

This report presents an analysis of the hydroelectric generating facilities installed in the McClellan-Kerr Arkansas River Navigation System. Installed capacity of the federally owned projects in the system totals 639 megawatts, and about 20 percent of the $1.2 billion invested in the system is allocated to power. Power production by the projects is marketed by the Southwestern Power Administration (SPA) and distributed through transmission lines owned by SPA and private utilities.

The economic values of the power generated by the system has greatly increased in the past few years. Annual benefits, based on the cost of producing equivalent power from a coal fired base load plant and a turbine driven peaking plant would increase the 14.2 million annual power benefits used in project justification to over $40 million per year.

Operation of the hydroelectric generation facilities provides annual savings equal to more than three billion tons of coal; four million barrels of oil; or about 26 million cubic feet of natural gas.

Hydropower projects are characterized by unique operational advantages and disadvantages. The system can be operated to go on line at full operating capacity almost instantaneously. The system can be shut down as quickly as electrical loads vary, and the stored water serves as stored energy. Thus the hydropower system can be operated to accommodate diurnal and seasonal variations in demand very efficiently. There are, however, limitations placed on operational capability from operational restrictions resulting from competing water uses and variable hydrologic conditions. The marketing agency (SPA) must therefore contend with its characteristics and limitations. Generally, purchase of power from thermal sources is required to balance the supply available from hydropower to fulfill contracted obligations. During periods of operational restrictions (primarily during low flow periods) considerable power must be bought from alternative sources to meet contracts.

The period of record covered in this report includes a wide range of hydrologic conditions, from periods of protracted excess flows such as 1973 to periods of limited flows such as 1971, but <u>not</u> the most recent experience of 1976 (a period of low flow). The report concludes that the estimates of average generation used for project evaluation studies were reasonably accurate.

The report also evaluates the financial payout from marketing the power generated by the system. Net revenues available to payoff the allocated construction costs were in deficit of $6.2 million thru 1974. The reasons are complex, but center on cost allocation procedures, enabling legislation for federal power marketing and the basis for power revenues. Comments from the Southwestern Power Administration suggest that definitive conclusions may have to wait for a longer period of experience with the project and that the issues are too complex to be adequately dealt with in a report of this type. We agree that the report

does not provide a complete basis for diagnosis of all of the problems. Nor does it provide recommendations for solving the problems. It does, however, show the current picture of the current conditions attendant to hydropower production and marketing, and offers some basis for comparing these conditions to those that were assumed at the time the projects were planned and designed.

HYDROELECTRIC POWER GENERATION

McClellan-Kerr Arkansas River Navigation System

PAGE

PLATES		PAGE

FIGURES

TABLES

TABLES (Continued)

HYDROELECTRIC POWER GENERATION
AT THE
McCLELLAN-KERR ARKANSAS RIVER NAVIGATION SYSTEM

GENERAL.

Description of Arkansas River Navigation Project. The Arkansas River Navigation Project is part of the Arkansas River Navigation System as defined by Congress in Public Law 91-649, January 5, 1971. The project for comprehensive development of the Arkansas River and tributaries was authorized by the River and Harbor Act of July 1946 as amended by Flood Control Acts of 1948 and 1950. It provides for a navigation route from the Mississippi River through Arkansas and Oklahoma to Catoosa, near Tulsa, OK; the production of hydroelectric power; additional flood control through upstream lakes and the related benefits of recreation and fish and wildlife enhancement. The navigation route begins at the confluence of the White River and the Mississippi, proceeds about ten miles via the White, through the manmade Arkansas Post Canal, up the Arkansas River, and up the Verdigris River, to Catoosa, OK, a distance of about 448 miles. The waterway was navigable to Little Rock, AR, in 1968, to Fort Smith, AR, in 1969 and navigation was completed to Catoosa, OK, in 1970. That part of the navigation route from the Mississippi River to Fort Smith, AR, was constructed by the Little Rock District and from Fort Smith to Catoosa, OK, by Tulsa District of the Corps of Engineers.

The navigation channel has a minimum depth of nine feet with 17 locks and dams (12 in Arkansas and five in Oklahoma) to assist in navigating the 420-foot rise in elevation from Mississippi River to Catoosa. Minimum

channel width is 300 feet on the Arkansas Post Canal, 250 feet on the Arkansas, and 150 feet on the Verdigris. Provision was made to widen the Verdigris channel to a minimum width of 300 feet when a sufficient volume of traffic makes enlargement of the waterway necessary. All bridges have been raised to provide a minimum vertical clearance of 52 feet 98 percent of the time. All lock chambers are 110 feet wide and 600 feet long. Lifts range from 14 to 54 feet. Seven major upstream lakes located in Oklahoma are Keystone, Oologah, Pensacola, Lake Hudson (Markham Ferry), Fort Gibson, Tenkiller Ferry, and Eufaula, all of which provide flood control storage. Hydroelectric power is generated at Dardanelle and Ozark Dams in Arkansas and at Robert S. Kerr, Webbers Falls, Keystone, Pensacola, Lake Hudson (Markham Ferry), Fort Gibson, Tenkiller Ferry, and Eufaula Lakes in Oklahoma. However, power has been deauthorized at the Oologah project. Two additional units are being considered for installation at Fort Gibson to supplement the initial installation of four units. Two of the upstream lakes, Pensacola and Lake Hudson (Markham Ferry), were constructed by the Grand River Dam Authority, an agency of the State of Oklahoma; both contain federally financed flood-control storage. The other upstream lakes were constructed by the Corps of Engineers, and all contribute significantly to the operation of the McClellan-Kerr Arkansas River Navigation System.

The bank stabilization and channel rectification work to control meandering of the Arkansas River and aid in the development of the navigation channel is an important feature of the overall project.

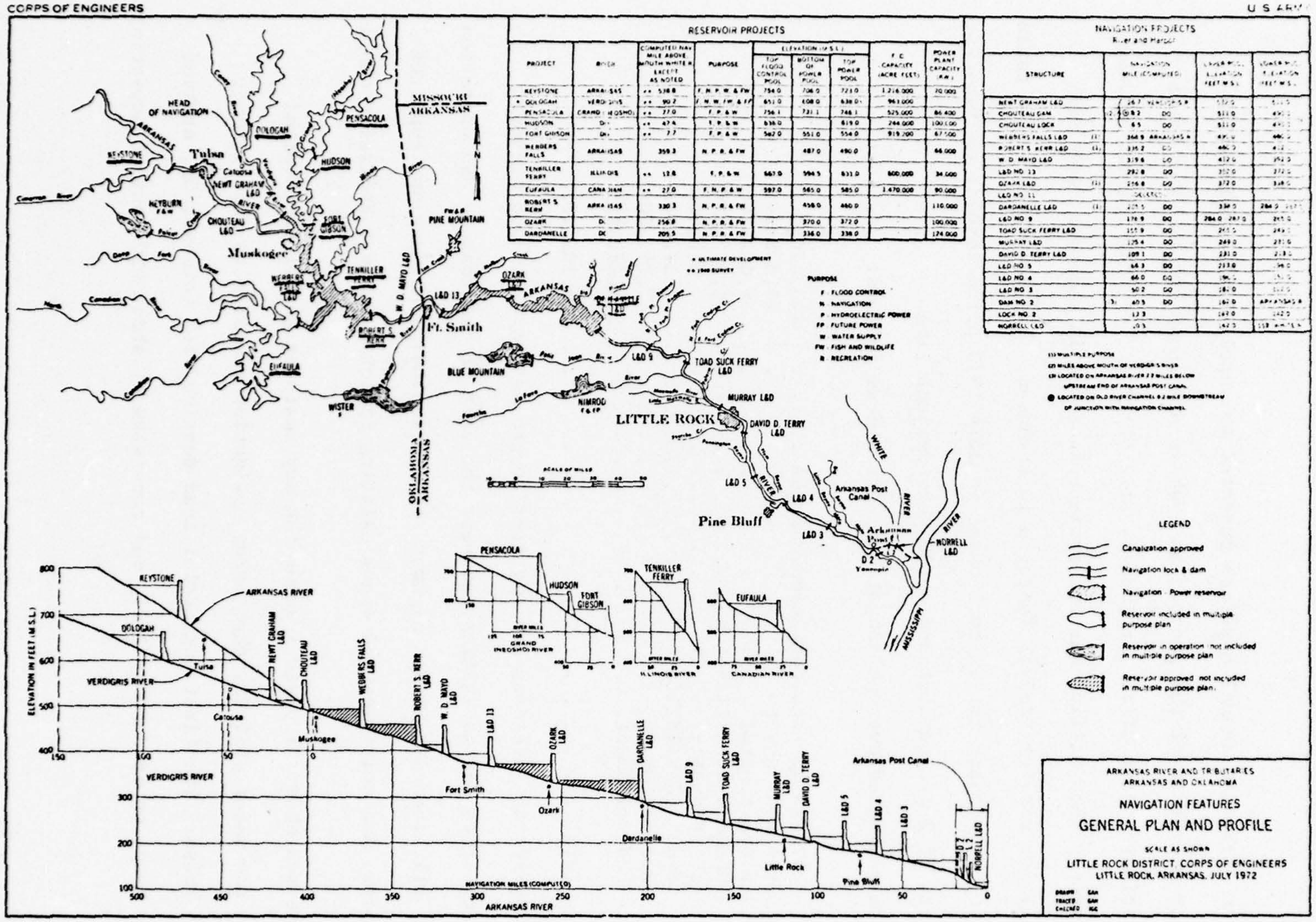
The estimated annual benefits expected to result from construction and operation of the project as a whole are shown below. The total estimated cost of the project is $1.2 billion. Of this amount, approximately $600 million was for project features in Oklahoma, and $600 million was for project features in Arkansas. The benefit-to-cost ratio for the project is 1.5 to 1 based on July 1970 price levels, an interest rate of 2 1/2 percent and a 100-year project life.

The estimated average annual benefits are as follows:

Savings in transportation charges	$40,470,000
Value of power.	14,838,900
Flood control	6,602,600
Channel stabilization	6,575,000
Water supply.	828,900
Fish and wildlife.	312,000
Recreation	2,297,000
Redevelopment.	3,355,800
Total	$75,280,200

Non-Federal interests are required to provide terminal and transfer facilities for navigation and bear the cost of maintenance and operation of all altered rail and highway routes, including bridges and appurtenances, and utilities and other existing improvements not Federally owned.

The map shown as plate 1 shows the key features and lifts involved in the water stairway that makes navigation possible to the vicinity of Tulsa. The first commercial load destined for Catoosa, OK, arrived by barge on 18 January 1971, and consisted of about 650 tons of newsprint.



RESERVOIR PROJECTS

PROJECT	RIVER	COMPUTED NAV. MILE ABOVE MOUTH WHITE R. EXCEPT AS NOTED	PURPOSE	ELEVATION (M.S.L.) TOP FLOOD CONTROL POOL	BOTTOM OF POWER POOL	TOP POWER POOL	F. C. CAPACITY (ACRE FEET)	POWER PLANT CAPACITY (K.W.)
KEYSTONE	ARKANSAS	** 538.8	F, N, P, W & FW	754.0	706.0	723.0	1,216,000	70,000
* OOLOGAH	VERDIGRIS	** 90.2	F, N, W, FW & FP	651.0	608.0	638.0	963,000	
PENSACOLA	GRAND (NEOSHO)	** 77.0	F, P & W	756.1	731.1	746.1	525,000	86,400
HUDSON	Do	** 47.4	F, P & W	636.0		619.0	244,000	100,000
FORT GIBSON	Do	** 7.7	F, P & W	582.0	551.0	554.0	919,200	67,500
WEBBERS FALLS	ARKANSAS	359.3	N, P, R, & FW		487.0	490.0		66,000
TENKILLER FERRY	ILLINOIS	** 12.8	F, P, & W	667.0	594.5	632.0	600,000	34,000
EUFAULA	CANADIAN	** 27.0	F, N, P & W	597.0	565.0	585.0	1,470,000	90,000
ROBERT S. KERR	ARKANSAS	330.3	N, P, R, & FW		458.0	460.0		110,000
OZARK	Do	256.8	N, P, R, & FW		370.0	372.0		100,000
DARDANELLE	DO	205.5	N, P, R, & FW		336.0	338.0		124,000

* ULTIMATE DEVELOPMENT
** 1940 SURVEY

PURPOSE
F FLOOD CONTROL
N NAVIGATION
P HYDROELECTRIC POWER
FP FUTURE POWER
W WATER SUPPLY
FW FISH AND WILDLIFE
R RECREATION

NAVIGATION PROJECTS
River and Harbor

STRUCTURE	NAVIGATION MILE (COMPUTED)	UPPER POOL ELEVATION FEET M.S.L.	LOWER POOL ELEVATION FEET M.S.L.
NEWT GRAHAM L&D	26.7 VERDIGRIS R	[illegible]	[illegible]
CHOUTEAU DAM	(2) ● 8.2 DO	511.0	[illegible]
CHOUTEAU LOCK	6.5 DO	511.0	[illegible]
WEBBERS FALLS L&D (1)	366.9 ARKANSAS R	[illegible]	[illegible]
ROBERT S. KERR L&D (1)	336.2 DO	[illegible]	[illegible]
W. D. MAYO L&D	319.6 DO	412.0	[illegible]
L&D NO 13	292.8 DO	[illegible]	[illegible]
OZARK L&D (1)	256.8 DO	372.0	[illegible]
L&D NO 11	DELETED		
DARDANELLE L&D (1)	205.5 DO	338.0	284.0 [illegible]
L&D NO 9	176.9 DO	284.0 287.0	[illegible]
TOAD SUCK FERRY L&D	155.9 DO	[illegible]	[illegible]
MURRAY L&D	125.4 DO	249.0	[illegible]
DAVID D. TERRY L&D	109.1 DO	231.0	[illegible]
L&D NO 5	86.3 DO	213.0	[illegible]
L&D NO 4	66.0 DO	[illegible]	[illegible]
L&D NO 3	50.2 DO	[illegible]	[illegible]
DAM NO 2	(3) 40.5 DO	[illegible]	ARKANSAS R
LOCK NO 2	13.3	[illegible]	[illegible]
NORRELL L&D	10.3	[illegible]	[illegible] WHITE R

(1) MULTIPLE PURPOSE
(2) MILES ABOVE MOUTH OF VERDIGRIS RIVER
(3) LOCATED ON ARKANSAS RIVER 2.2 MILES BELOW UPSTREAM END OF ARKANSAS POST CANAL
● LOCATED ON OLD RIVER CHANNEL 0.2 MILE DOWNSTREAM OF JUNCTION WITH NAVIGATION CHANNEL

LEGEND
Canalization approved
Navigation lock & dam
Navigation - Power reservoir
Reservoir included in multiple purpose plan
Reservoir in operation - not included in multiple purpose plan
Reservoir approved - not included in multiple purpose plan

ARKANSAS RIVER AND TRIBUTARIES
ARKANSAS AND OKLAHOMA
NAVIGATION FEATURES
GENERAL PLAN AND PROFILE
SCALE AS SHOWN
LITTLE ROCK DISTRICT, CORPS OF ENGINEERS
LITTLE ROCK, ARKANSAS, JULY 1972

PLATE 1

Figure 1 shows a schematic stream-flow diagram showing the relative locations of the projects considered in this report.

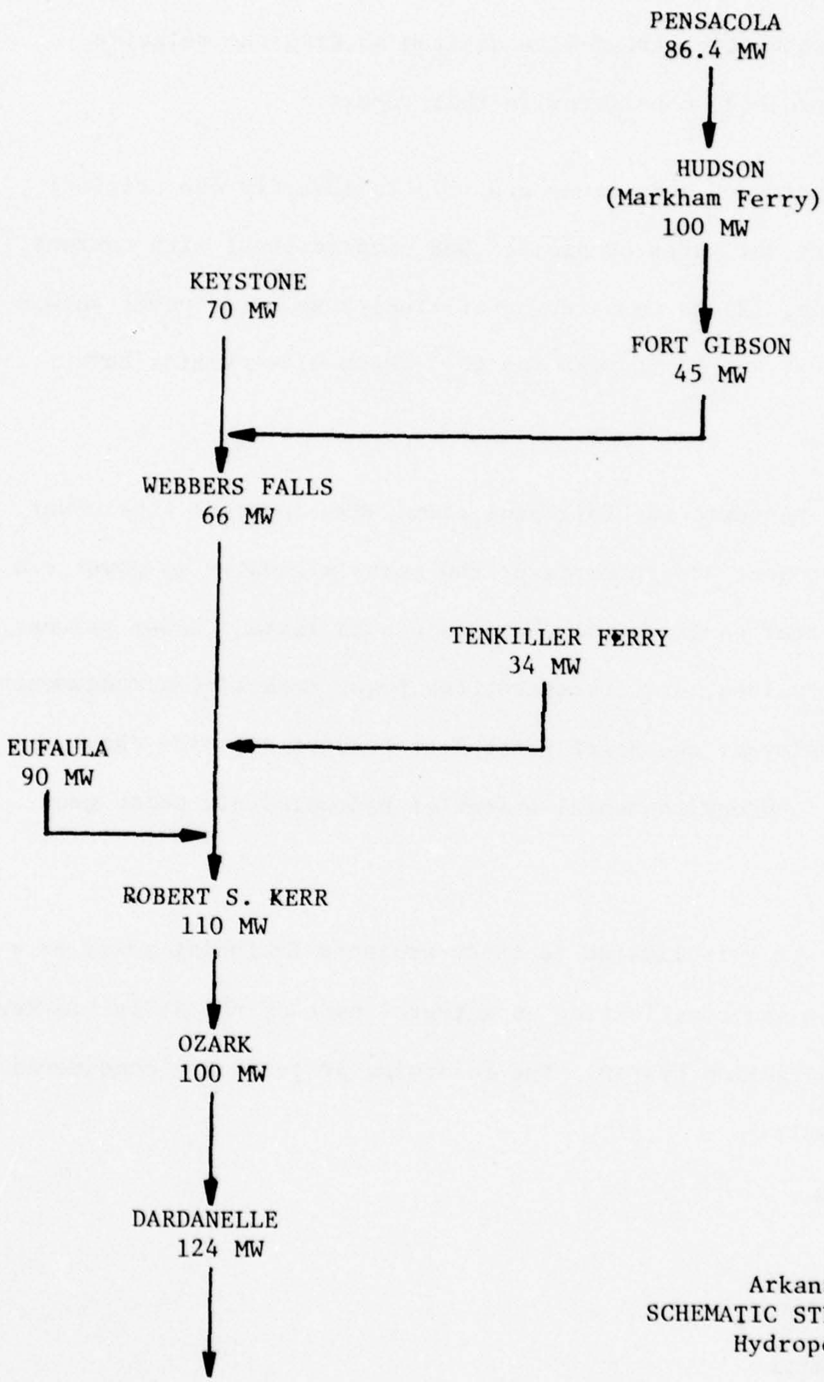
Purpose. The purposes of this study are (1) to identify the original capacity and energy estimates by project and compare these with current capacity and energy, (2) to compare the originally selected power values with current values, and (3) to examine the system of marketing power.

To accomplish the purposes the following items are covered: the power aspects of each project are summarized; the costs allocated to power are identified; the power generated at each project is listed; power values, including current values, are discussed; the power marketing arrangements and rates are displayed; and brief general statements are made about the economic, social, and environmental effect of hydroelectric power generation.

The scope of the study is limited to those projects including power as a functional purpose and constituting an integral part of the McClellan-Kerr Arkansas River Navigation System. The following projects are considered:

Mainstem projects,

- Dardanelle
- Ozark
- Robert S. Kerr
- Webbers Falls



Arkansas River
SCHEMATIC STREAMFLOW DIAGRAM
Hydropower System

Figure 1

Upstream project,

Keystone

Tributary projects,

Eufaula

Tenkiller Ferry

Fort Gibson

Oologah

Of the above listed nine projects, installation of the authorized power generating facilities has been deauthorized at one, Oologah, leaving eight projects for study in some detail in this report.

Two other tributary projects which produce power are the Hudson and Pensacola projects located on the Grand River. The projects were built and are operated by the Grand River Dam Authority and have Federal flood control storage capacity included in the reservoirs. Also, additional power is produced by the Grand River Dam Authority at the Salina pumped-storage project on the Salina Creek, a tributary of the Grand River. Significant quantities of power are generated and marketed annually from this group of projects. They are not Federal power projects, and for this reason were not studied for this report.

System operations. The projects considered in this report are physically interconnected in two ways. The first interconnection concerns stream flow. The table on plate 1 shows that Keystone, Pensacola, Tenkiller,

and Eufaula provide a significant amount of storage space in the reservoir exclusively for power operation. During moderate to high river discharges, this storage is filled to the extent practicable. During subsequent periods of low natural flows when power generation would be minimal, water is released to increase power generation at the project and at downstream power installations as diagrammed on figure 1. This procedure constitutes system operation of the power resources, and permits generation of substantial amounts of power throughout the year, whereas such power generation might otherwise be limited to local rises on the streams.

In addition, seven upstream lakes provide flood-control storage. This storage is in addition to power storage, and is used only during periods of high flows. The projects with flood-control storage include Keystone, Fort Gibson, Tenkiller Ferry, and Eufaula, as well as Oologah (power deauthorized), and Markham Ferry and Pensacola of the Grand River Authority. Part of the flood flow is retained in the "flood control" storage in the reservoir to lower flood stages (and damages) downstream. As soon as practicable, the water in the flood control storage zone is released to make the storage space available for subsequent flows which could cause flooding. Thus, the use of flood control storage tends to reduce the magnitude of high streamflows, but extends the duration of periods of moderate flow. Ordinarily, this process of temporarily storing flood flows for later release increases the amount of water available for use in generating

hydroelectric energy. Because of the need to evacuate flood-control storage as soon as possible, the additional energy resulting from the release of temporarily stored floodwaters is normally available only during the immediate post flood period.

Despite the fact that Pensacola and Lake Hudson (Markham Ferry) projects are not Federally owned, a portion of the storage space that has been provided at Federal expense is reserved for flood control purposes. Under Section 7 of the Flood Control Act of 1944, the Corps of Engineers is responsible for developing rules governing the use of flood control storage provided at Federal expense. Accordingly, the Corps has developed a plan of flood control regulation for Pensacola and Lake Hudson to coordinate their flood control operation with the operation of other projects in the system. The Grand River Dam Authority operates the projects according to this plan during periods when flood control storage must be utilized.

The foregoing constitutes operation of the interconnected reservoirs to secure effective flood control. The same group of interconnected reservoirs together with the mainstem low-head dams are operated as a different kind of system, that is, a system to secure effective navigation even during periods of low natural flows when the system must be operated to secure sufficient navigation channel depth by increasing flows. Other McClellan-Kerr Arkansas River Navigation System purposes such as recreation, fish and wildlife enhancement, etc., also require some degree of system operation of the interconnected reservoirs.

The second kind of physical interconnection among the individual projects of the Arkansas River Navigation Project is provided by the SPA transmission lines connecting the projects with power as diagrammed on plate 2. These power projects, except Keystone, however, are connected directly to one SPA transmission network along with Denison, Bull Shoals, Norfork and Greers Ferry, all Corps projects. Interconnections with utility company transmission lines provides a system powered by the projects already referred to and by numerous other Corps power projects as well as by utility company generating facilities. The system distributes the power to customers in the general service area including customers of SPA. Operation of the total system affords a substantial gain in operational flexibility, and affords an opportunity to firm up low flow period hydro energy with off-peak thermal energy.

Power values. The Federal Power Commission (FPC) estimates the value of power from each proposed Federal multiple-purpose project to determine whether inclusion of power generating facilities is economically justified. This report summarizes background material concerning (a) the factors considered in estimating the values of power, (b) the values per kilowatt per year and per kilowatt-hour used at various times and (c) the recent rapid increase in the value of power resulting from the increases in cost of fuels, costs of constructing alternative power sources and interest rates.


GOVERNMENT OWNED FACILITIES
KANSAS
MISSOURI
OKLAHOMA
ARKANSAS
TEXAS
LOUISIANA
UNITED STATES
DEPARTMENT OF THE INTERIOR
SOUTHWESTERN POWER
ADMINISTRATION
TRANSMISSION SYSTEM
POWER MARKETING FACILITIES

Plate 2

Responsibility for sale of power. Although the Corps of Engineers constructs and operates the power projects considered in this report, the Corps does not market this power. Power produced at Corps projects is delivered to the Southwestern Power Administration (SPA) at the high voltage terminals of the power-house switchyards, transmitted to demand centers over transmission lines, some of which are owned by SPA as diagrammed on plate 2, and sold to preference customers. Described later in this report is the authority for this procedure, existing power marketing contracts and prevailing rates.

Other reports. The US Army Institute for Water Resources (IWR) published a report entitled: "Hydroelectric Power Potential at Corps of Engineers Projects," dated July 1975. It deals generally with Corps power projects over the entire United States where this report deals in a limited manner with power projects associated with the McClellan-Kerr Arkansas River Navigation System.

University of Texas. The University of Texas, Austin recently published a report entitled: "Influence of Alternative Technologies on Energy Supply" by the Electrical Engineering Department and the Center for Energy Studies. This report indicates that the technologies used today in our energy-supply system are highly developed but extensive work is being done to develop alternate technologies. This report also states that the motivation for this work generally is derived from several desires— such as: (1) to make more efficient use of our resources, (2) to deliver energy at lower cost, (3) to reduce environmental impacts of energy uses, and (4) to make available alternate energy sources. The discussion of the report divided the

subject-matter into four categories:

(1) technologies for improving our use of presently-available primary energy sources,

(2) technologies to permit the use of alternate primary energy sources,

(3) alternative technologies for energy conversion, storage, and delivery, and

(4) alternative technologies for energy utilization.

The report concludes that, since hydraulic energy depends upon natural precipitation and topography, and the technology for its development is well-known and mature, there is doubt that any major influence of alternative technologies on hydraulic energy development will materialize. However, the large thermal plants now in use produce electrical energy most efficiently when their output is varied only slightly. This contrasts greatly with normal system loads which vary between widely separated extremes. Since no economical means exist at present for storing electrical energy, other methods for supplying peak loads while maintaining essentially steady loads on the base load generating units must be used. Principally, two means of generating peak loads are presently considered for new construction. These are (a) combustion turbines, and (b) pumped-storage hydro installations. Existing conventional hydro and older, less efficient thermal plants are also used for this purpose. In the latter, the machines operate as pumps using off-peak energy pumping water from a low lake to a higher one. During peak load periods, this pumped water runs through the machines, now operating as turbines, to contribute to the system peaking capability. This use of pumped storage levels out the load on other plants while also adding peaking capability. Conventional hydroplants and older thermal plants are also used for peak loads.

Arkansas-White-Red Rivers System Conservation Studies. A report dated November 1971 entitled, "Preliminary Study of Operating Guide Curves for Power Production," presents results of preliminary studies made by the Southwestern Division, Little Rock District, Tulsa District, and the Hydrologic Engineering Center concerning the system operation of the Federally owned hydroelectric power plants on the Arkansas, White and Red (AWR) Rivers whose output is sold by the Southwestern Power Adminsitration (SPA) to preference customers.

SPA contracts for the sale of firm power (that is, electric energy of assured availability to the customer to meet agreed upon load requirements) amounting to approximately the median year output of the Federally owned plants. This results in the need for SPA to provide energy from other sources to firm up hydropower during years having flows less than median year flows. This additional energy is usually purchased off-peak from investor owned utilities operating thermal power plants. The purchased energy permits the sale, as firm energy, of a greater portion of the hydroelectric energy which otherwise would have had to have been marketed as secondary or dump energy.

The AWR report points out that the base or minimum SPA load is quite small compared to the capacity of the Arkansas run-of-the-river power plants (that is, Dardanelle, Ozark, Robert S. Kerr, and Webbers Falls) and that these plants operate continuously at full capacity for extended periods during high to flood flows. The result is that the full flood period output of these plants cannot be used during periods of low SPA loads and consequently must be marketed as secondary energy.

The AWR report presents results of computer simulations of operating the AWR reservoirs, hydropower plants, and supplementary thermal power plants according to various system guide curves to meet monthly SPA system loads specified for the fiscal year 1971. A guide curve in this context consists of a graph in which system hydro energy in storage (that is, the work, in kilowatt hours, which the water held in reservoir storage can accomplish when passed through the project power plant and downstream power plants) is plotted vertically. The months of the year are plotted horizontally. One or more boundary lines varying in height above the base line according to the season of the year divide the graph into two or more horizontal bands. The uppermost band (when large amounts of energy are in storage) might indicate that hydropower can meet all SPA loads and provide excess energy for marketing as well. When the season and the amount of energy in storage plot in this upper band, the AWR hydro power plants would be operated accordingly. On the other hand, when system energy storage is at a minimum, the guide curve might specify minimum hydroelectric generation at AWR plants and that the hydropower be supplemented by maximum purchase of off-peak thermal energy. Intermediate bands specify intermediate hydroelectric generation supplemented by a moderate amount of thermal energy.

The lines separating the horizontal bands of the graph constitute the "guide curves." These were set to obtain best or predetermined results. A lower guide curve was established by adjustments to a sequential routing program. These adjustments were made until a guide curve was achieved that provided for the virtual emptying of the system power storage.

The routing used monthly flows for the years 1923 through 1967, derived specifically for the AWR guide curve study. The flows may differ from other published averages and average flows used in individual project studies. A second guide curve was assumed at the top of the system conservation storage. A third guide curve was assumed midway between the other two.

The AWR guide curve studies indicated the following:

a. The average annual energy for the three guide curves differed, from the highest to the lowest, by about one part in 250.

b. The contribution by the AWR hydro projects to firm energy can be expected to increase as the guide curve is lowered. The increase from the highest guide curve to the lowest is about five percent.

c. The lower the guide curve, the smaller the amount of energy that must be marketed a secondary.

d. The higher the guide curve, the greater the AWR hydroelectric contribution to the capacity requirements of the SPA load.

e. Present drawdown limits are such that the minimum AWR peaking capability is about 13 percent less than the installed capacity when all the reservoirs are all drawn to their limits. Reducing drawdown has the effect of increasing system dependable capacity.

Other purposes of the projects in the AWR system were considered, but not to the extent that power was considered.

The AWR report on guide curves states that the short term objective of the study of developing operation procedures for generating power by the AWR

system reservoirs while maintaining the status quo of the other project purposes was not achieved. The report recommended further study to establish system guide curves of the type examined during the AWR study together with reconsideration of changes in conservation pool levels, possibly by season, and re-examination of certain basic data.

SPA commented that the AWR study did not produce a regulation concept adequate for actual operation, although the results did provide a basis for further studies. SPA did point out that changing conservation pool levels at individual projects would necessitate a change in cost allocation, particularly the amount allocated to power. Little Rock District felt that an urgent need existed for a simple basic plan for operation of the AWR reservoirs, and objected to the use of thermal purchases as a factor in the routing procedure since purchase of thermal energy was solely the responsibility of SPA. Little Rock also favored constant generation during a particular month from one year to the next with no regard to the drawdown of system in storage below the guide curve. Tulsa District was concerned about the basic study assumption that SPA loads must be met. Before a guide curve is adopted which provides for meeting such loads, the costs and benefits of such a procedure should be considered.

ROLE OF THE FEDERAL POWER COMMISSION.

Introduction. The Federal Power Act authorizes the Federal Power Commission (FPC) to make investigations of the water resources of any region to be developed, to cooperate with the executive departments and other agencies of Federal and State Governments in water resources planning, and to issue

licences to non-Federal interests for the construction and operation of developments for hydroelectric power and other purposes. Also, under the provisions of the Flood Control Acts, and River and Harbor Acts, the Commission furnishes advice to Federal Agencies on power phases of Federal multiple purpose projects.

Power benefits. The benefits of power produced by a hydroelectric project are equivalent to the value of the power to the users as measured by the amount they would be willing to pay for such power. Normally, the cost from the most likely alternative source provides an appropriate measure of the value of the power to the project.

Normally, the value of electric power is evaluated in terms of two components-capacity and energy. The capacity value is derived from a determination of the fixed costs of the selected alternative source of supply. The energy value is determined from costs of the alternative which relate to and vary with the energy output of the alternative plant. These capacity and energy components of power value are usually expressed as dollars per kilowatt per year and mills per kilowatt-hour of average annual energy. Power values for hydropower plants are customarily estimated by the Federal Power Commission on the basis of the cost of power from a privately financed alternative source. Most often, the alternative source is a modern, conventional steam electric plant located as favorably as possible to the market which would be served by the hydropower plant. The process of estimating the at-site unit power values begins with the at-site unit costs for

capacity and energy estimated for the privately financed alternative steam plant. These unit costs are increased according to the costs and power losses associated with (a) a steam-electric sending substation, (b) transmission lines from the steam-electric plant to the market, and (c) the steam electric receiving station at the market. The resulting values represent the cost of steam-electric power at the low-tension connection at the market. These costs are then modified by hydro-steam adjustments to derive the unit benefits of hydroelectric power at the low-tension connection at the market. The hydro-steam capacity adjustment (an increase) is made to account for the fact that most hydroelectric plants are particularly adapted to serving peak loads and operating as synchronous condensers or as spinning reserve. Under favorable water conditions they may also supply capacity in excess of the dependable capacity of the plant. In certain situations, the addition of a hydropower plant to a system displaces the addition of a low cost baseload thermal plant to the system which would lower the average cost of the system thermal energy. In such cases, a negative adjustment to the cost of steam electric energy at the low tension connection at the market is made to determine the unit energy benefit of hydropower at the same location. The unit benefit values of hydroelectric power at the low tension connection at the market are then reduced according to the costs and power losses associated with (a) the hydroelectric receiving substation at market, (b) transmission lines from the hydroelectric plant to the market, and (c) hydroelectric sending substation. The resulting values constitute the unit power values at the hydroelectric power plant generator.

Hydropower is customarily authorized for those Corps projects where its inclusion appears economically justified and where a market exists for the power. One test of justification is to determine whether power benefits exceed the costs allocated to power. The Federal Power Commission in accordance with its authorities and responsbilities, furnishes the Corps unit power values as described above for the Corps justification studies of each individual project. The Corps then applies the unit value of capacity to the dependable capacity of the project under consideration. Dependable capacity is defined for the purposes of this report as the load carrying ability of a particular hydropower project under adverse hydrologic conditions for the time interval and period specified when related to the characteristics of the load to be supplied. The unit value of energy is applied to the project's average annual capability of doing work which is measured as the average annual output of the hydroplant in question measured in kilowatt-hours. The sum of the two components is the average annual power benefit of the project.

<u>Alternative generating plant costs.</u> As previously stated, the most likely alternative source of electrical power is usually considered to be a privately financed (investor owned) thermal generating plant. Investor owned facilities are burdened with costs not applied to government-owned facilities. These additional costs include a larger interest rate, insurance (Federal projects are considered insured by the Federal government) and taxes (Federal income, Federal miscellaneous, and state and local). For example, the projects considered in this report were studied using a 6 percent private interest

rate and a 2 1/2 percent Federal interest rate. Obviously the assumption of a federally-owned alternative thermal power plant would result in lesser unit benefits for the Federal hydropower installations. However, it has not been the general policy of Congress to authorize federally financed thermal plants. Senate Document 97 did , however, provide that power which could be produced at a Federal hydropower project be produced at a cost less than the cost of producing equivalent power from a thermo-electric plant assumed to be federally financed. FPC notes that this comparability test overlooks advantages of hydropower projects such as (a) hydro projects use a renewable resource while thermal plants do not, (b) hydropower projects do not contribute to air pollution while thermal plants do, and (c) inclusion of hydropower as a project purpose in a multipurpose project may make possible development of other project purposes that otherwise would be precluded from development.

ROLE OF THE SOUTHWESTERN POWER ADMINISTRATION

Authority. Section 5 of the Flood Control Act of 1944 is quoted as follows: "Section 5. Electric power and energy generated at reservoir projects under the control of the War Department and in the opinion of the Secretary of War not required in the operation of such projects shall be delivered to the Secretary of the Interior, who shall transmit and dispose of such power and energy in such a manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles, the rate schedules to become effective upon confirmation and approval by the Federal Power Commission. Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such

rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years. Preference in the sale of such power and energy shall be given to public bodies and cooperatives. The Secretary of Interior is authorized, from funds to be appropriated by the Congress, to construct or acquire, by purchase or other agreement, only such transmission lines and related facilities as may be necessary in order to make the power and energy generated at said projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal Government, public bodies, cooperatives, and privately owned companies. All moneys received from such sales shall be deposited in the Treasury of the United States as miscellaneous receipts."

The Southwest Power Administration (SPA) was formed as an agency of the Department of the Interior to carry out the provisions of the above quoted section 5.

Preconstruction role. During the planning stages, SPA is contacted for an evaluation of the power produced to determine whether it will be possible to market the power from proposed projects at rates sufficient to pay off the investment allotted to power. This information supplements that furnished by the Federal Power Commission in formulating plans for hydroelectric plants.

Postconstruction role. The postconstruction role of SPA consists of marketing power produced at Federal Projects constructed by the Corps of Engineers in an area comprising all of Arkansas and Louisiana, and portions of Missouri, Kansas, Texas, and Oklahoma. Much of the following data on the SPA postconstruction role was abstracted from the Institute for Water Resources report 75 R-1, July 1975, entitled "Hydroelectric Power Potential at Corps of Engineers Projects." The power projects in the SPA system are listed in table 1.

Table 1. Summary of power project capacity and cost, Southwestern Division Corps of Engineers, 1975.

Project	On-line date	Installed Capacity, kw	Cost allocated to power $ million
Beaver	1965	112,000	33.9
Blakely Mountain	1956	75,000	25.1
Broken Bow	1970	100,000	23.8
Bull Shoals	1953	340,000	60.0
Dardanelle*	1965	124,000	45.4
DeGray	1972	68,000	22.7
Denison	1945	70,000	20.7
Eufaula*	1965	90,000	34.3
Fort Gibson*	1953	45,000	16.8
Greers Ferry	1964	96,000	34.1
Robert S. Kerr*	1972	110,000	42.2
Keystone*	1968	70,000	26.8
Narrows	1951	25,500	7.4
Norfork	1944	70,000	13.8
Ozark*	1973	100,000	47.2
Sam Rayburn	1967	52,000	23.7
Stockton	1973	45,200	25.1
Table Rock	1959	200,000	53.9
Tenkiller Ferry*	1954	34,000	12.0
Webbers Falls*	1974	60,000	27.3
Whitney	1965	30,000	8.3
		1,916,700 kw	$604.5

*Considered in this report. Nominally within the scope of this report are the Markham Ferry and Pensacola Projects on the Grand (Neosho) River. Information on these projects is not included in this report since they are under the control of the Grand River Dam Authority.

The SPA system can be divided into two main categories: (a) integrated system projects which are interconnected and operated to some degree as a combined source, and (b) isolated projects, Narrows, Sam Rayburn, and Whitney projects, from which the power output is sold for a fixed annual amount and delivered to the transmission systems of other utilities.

Marketing power. SPA markets power to preference customers under five general rate schedules, according to information contained in the IWR report 75-1,entitled "Hydroelectric Power Potential at Corps of Engineers Projects," July 1975. Which schedule and associated marketing arrangement applies to a particular customer is decided on an individual basis. The five schedules are:

Schedule	Kind of service	Capacity charge in $/kw/mo. of billing demand	Energy charge in mills /kwh/kw of billing demand	Availability
F-1	Firm power	$ 1.60	2.0 for 150 kwh; 3.0 for 290 kwh; 5.0 for rest.	Firm
P-2	Peaking power	$ 1.20	2.0	To wholesale customers as available, 1200-2400 kwh/kw/yr. as specified in contract.
EE	Excess energy	NA*	1.5	To wholesale customers when available.
ES	Emergency service	$ 0.045**	3.7	To wholesale customers.
IC	Interruptible capacity	$ 0.045**	2.0***	To wholesale customers when available.

* Not applicable.
** Per kw per day of service.
*** As an alternative, energy can be returned to SPA as scheduled by SPA.

COST ALLOCATION STUDIES

Introduction. In order to fulfill the requirements of Section 5 of the Flood Control Act of 1944, cost allocation studies have been performed on all Corps of Engineers projects with power plants considered in this report. Such studies are not available in the SWD files for the Pensacola and Markham Ferry projects since these projects are controlled by the Grand River Dam Authority. Of the eight cost allocation studies available on the projects considered in this report, only those for Eufaula, Tenkiller Ferry, and Fort Gibson are indicated to have been "adopted" on the "Power Project Data Sheets."

The allocation studies were made to determine equitable distribution of the various multi-purpose costs among all authorized purposes, especially power, in accordance with the Flood Control Act of 1944 which required recovery of capital investment allocated to power. An agreement among the Department of Interior, the Department of the Army, and the Federal Power Commission, dated 12 March 1954, defined the procedure and listed acceptable methods to be followed in the allocation of costs of multiple purpose projects. Based on this agreement and on subsequently developed standards and procedures, cost allocations for the projects considered in this report, with the exceptions noted above, were based on the separable cost-remaining benefits method.

Description of cost allocation method. The separable costs-remaining benefits method consists of (1) determining the separable cost of including each function in a multiple purpose project, and (2) determining an equitable distribution of the joint costs incurred for several purposes in common. The separable cost for each project purpose is the difference between the cost of the entire multiple-purpose project and the cost of a project with that purpose omitted. Joint costs are defined as the difference between the cost of the entire multiple-purpose project as a whole and the total of the separable costs for all project purposes. From the estimated benefits or alternate costs, whichever is less, separable costs are deducted to give remaining benefits. Joint costs are distributed in proportion to the remaining benefits for each purpose. The sum of separable costs and distributed joint costs for each purpose constitutes the total cost allocated to that purpose. By subtracting the separable cost from the benefits or alternate costs, whichever is less, for a purpose, the cost allocated to that purpose is limited to the separable cost as a minimum and the benefits or alternative costs as a maximum.

The cost allocation studies all exclude costs for specific recreational facilities and road replacement over replacement in kind from project costs allotted to other purposes.

Annual costs and charges. The average annual operation and maintenance costs were estimated on the basis of experience gained from actual operation and maintenance of similar projects. The annual cost of operation and maintenance for specific recreation facilities is excluded from the total project

annual operation and maintenance cost. The estimated average annual costs of major replacements were estimated on the basis of charges equal to 25 percent of the cost of hydraulic, mechanical, and electrical equipment at the end of 33 and 67 years. The annual cost was determined by amortizing the present worth of the estimated expenditure 33 and 67 years hence at 2-1/2 percent interest over the assumed project life of 100 years.

Interest during construction was computed on the basis of (1) actual fiscal year expenditures for the study period, (2) actual monthly expenditures during the construction period to the time the allocation study was made, and (3) scheduled expenditures for the remaining portion of the construction period. The expenditures for items in each cost account were classified as specific or joint-use costs. Interest during construction on the total specific and joint-use expenditures was computed separately at 2-1/2 percent simple interest per annum from the middle of the period in which the expenditure occurred until the first of the month following availability for service of the items for navigation or power. Each of the generating units was considered available for service in the month in which it went into operation. Each project was considered available for navigation on the date the navigation lock is scheduled for completion. The in-service date for these functions was considered as the first of the month following their availability for service. On the scheduled in-service date for a particular function, the cost of the joint-use facilities allocated to that function was also considered in service, and interest during construction

for those costs, as well as specific costs, was discontinued. Interest on expenditure after the in-service dates was considered operating expense.

The costs of specific recreation facilities and road relocations over replacement-in-kind were excluded from the construction expenditures before making an allocation of costs to navigation and power; therefore, interest during construction has not been computed for those costs.

The estimated average annual charges include, (1) interest on the Federal investment computed at 2-1/2 percent, (2) the amount necessary to amortize the investment in 100 years at a 2-1/2 percent interest rate, (3) the average annual cost of operation and maintenance, and (4) the average annual amount necessary for replacement of items having an estimated life of less than 100 years. The annual charges for interest and amortization are on the basis of the approved cost estimate in use at the time of the allocation study less the estimated cost of specific recreation facilities and road relocations over replacement-in-kind plus the interest that would accrue during the construction period.

Benefits. In determining the annual power benefits for the project, at-site unit power values were obtained from the Federal Power Commission, Fort Worth Regional Office. The unit values, determined as previously described, were applied to the amount of power expected from each project to determine total power benefits at the project site.

Alternative projects. The basic data used in preparing the plans and cost estimates for the alternative single-purpose projects were the same as those used in developing the plan and cost estimate for the multiple-purpose project. In developing the cost estimates for the alternative projects, the dams were assumed to be of the same general type and located at the same site as the multiple-purpose project. Unit prices used in the alternative single-purpose project estimates are comparable to those used in the multiple-purpose project estimate. The estimated operation and maintenance and major replacement costs for the alternative projects are generally on the same basis as those for the multiple-purpose project.

Summary of costs allocated to power. The results of the cost allocation studies performed to date are summarized in table 2. Data in the table show that the estimates for the eight projects varied in total investment cost from a low of about $23,400,000 for Tenkiller Ferry to a high of about $122,800,000 for Keystone. The percentage of the estimated total investment cost allocated to power ranged from a low of almost 25 percent for Keystone to a high of almost 57 percent for the Ozark project. Current cost estimates, shown in the lower portion of the table, for total investment are very near the cost estimated originally, except in the two instances of Ozark and of Webbers Falls. These two projects cost substantially more than the original estimates. Also, the percentages allocated to power at all the projects are approximately the same as in the previous cost allocation estimates. For each of the projects for which cost allocation studies were made (eight in all), the current approved estimate

TABLE 2

DATA ON COST ALLOCATION STUDIES

	DARDANELLE	OZARK	ROBERT S. KERR	WEBBERS FALLS	EUFAULA	KEYSTONE	TENKILLER FERRY	FORT GIBSON
Cost Allocation Study Data								
Date of report	9-73	9-66	8-67	4-67		6-74	12-57	12-57
Price level	7-65	7-66	7-66	7-66		68	6-56	6-56
Ave. annual energy, 10^6 kwh	613	429	459	213.3	317	228	114.5	190.5
Dependable capacity, 1000 kw	124	100	110	66	88	70	28	45
Benefit/kwh, mills	2.1	1.9	1.9	1.9	1.9	1.9	1.15	1.15
Benefit/kw/yr $	17.50	16.00	16.50	16.50	17.00	18.50	19.90	19.90
Power benefits, $1,000 1 yr.	3457	2415	2687	1494.3	1916.3	1625	689	1115
Date of est. of unit power benefits	1-65	1-64	66	66	64	68	53	53
Other functions in allocation	N	N,R	N,R,FW	N,R,FW	F,N,WS,FW	F,N,WS,FW	F	F
Funds in $1000								
Total investment	82779.1	69194.7	97484	79061	117221	122791	23383.1	43624.1
Investment alloc. to power	43259.5	39329.7	41146	25385	33363	30612	11800.7	16957.8
Construction expenditures	75758.0	64480.7	91841	74713	110682	113866	22073.6	40895.5
Construction Expend. alloc. to power	40718.6	36821.7	38730	23885	31796	28298	11160.4	16102.3
Percentages allocated to power								
Of total investment	52.26	56.84	42.21	32.11	28.46	24.93	50.47	38.87
Of construction expenditures	53.75	57.10	42.17	31.97	28.73	24.85	50.56	39.37
Information from "Power Project Data Sheets", Nov. and Dec. 1974								
Average annual energy, 10^6 kwh	613	429	459	213.3	317	228	114.5	190.5
Dependable capacity, 1000 kw	124	100	110	66	88	70	28	45
Benefit/kwh, mills	2.0	1.9	2.0	1.9	1.9	2.0	1.15	1.15
Benefit/kw/yr, $	20.50	16.00	20.50	16.00	17.00	21.50	19.90	19.90
Power benefits, $1000/yr	3788	2415	3173	1461	1916.3	1842	748.6	1115
Date of est. of unit power benefits	63	64	1-66	7-64	64	1-63	1-62	1-62
Information "Cost Allocation Data" sheets dated December 1974 and accompanying "Power Project Data Sheets"								
Allocation adopted	None	None	None	None	Adopted as above	None	Adopted as above	Adopted as above
Current Approved estimates ($1,000)								
Investment	86551.1	90462.4	96083.2	85301.1	117929	122464	241059	43999.6
Investment to power	45264.9	47237.5	40929.9	27777.6	33615	26785.6	11986.6	17243.3
First Cost	79470.0	86103.5	90512.0	80260.0	111390	114267	22796.4	41271
First cost to power	42684.0	44724.6	38551.9	26268.8	31899	25450.8	11346.3	16174
Percent, invest. to power	52.30	52.2	42.5	32.56	28.50	21.87	49.72	39.19
Percent, first cost to power	53.71	51.9	42.6	32.73	28.64	22.27	49.77	39.19
Allocated investment at end of FY 74	45517.8	48749.2	42197.3	28036.0	34311.4	26826.5	12046.8	16759.8

differs from that used in the original cost allocation studies. It is understood that the percentage of the total cost allocated to power was intended to be used with the current approved estimate to determine the amount currently allotted to power. Current approved estimates and amounts allotted to power appear on the "Cost Allocation Data Sheets" prepared for each power project regularly. Information extracted from December 1974 "Data Sheets" and "Cost Allocation Data" are presented on table 2 for comparison with the data taken from cost allocation reports. It is noted that power data taken from the cost allocation reports differ slightly from the data from the "Power Project Data Sheets." Power data are changed as (a) storage is reduced by sedimentation, (b) tailwater levels change, (c) flow record lengthens (d) more severe low-flow periods occur, etc. The data on the preceding table indicate that the percentages derived in the cost allocation studies are not used on the "Cost Allocation Data" sheets. The differences are small, and again, the reason for the differences is not known.

Use of results. The Finance and Accounting Branch in SWD carries running accounts on each project in terms of total first cost, investment, first cost allocated to power and investment allocated to power. The last named value is given on the last line of table 2. This amount represents the cost to be recovered as required in section 5 of the Flood Control Act of 1944. It was not possible to check the values precisely; they do, however, appear to be very nearly consistent with the values established by the cost allocation study.

POWER PLANT PERFORMANCE.

Introduction. Data on power production were assembled from SWD and districts to compare the output expected during the planning stages with the actual plant performance. Monthly summaries are prepared by each district for each hydroelectric power plant on SWD Form 584-C. A copy of a completed form for the Dardanelle power plant for January 1970 is attached as figure 2 for ready reference. Annual energy generation data are also available from "Power Project Data Sheets" on a fiscal year basis.

Output. Major factors which affect the output of a hydroelectric plant are, (1) availability of water, (2) availability of load, and the (3) availability of the plant. The latter factor concerns the portion of the time in which parts or all of the power plants are shut down for repair, maintenance, or inspection. These factors, as evidenced by the basic data described above are discussed in the following paragraphs.

Flows. Average annual flows at the power project sites are compared with annual power and flood control releases in the following table.

Project	Flows in cubic feet per second					
	Mean	1970	1971	1972	1973	1974
Dardanelle(1) (2)	33,500	33,000	26,600	21,400	92,600	65,500
Ozark (1) (2)	33,800	(4)	(4)	(4)	88,100	62,200
Robert S. Kerr (1) (3)	28,780	(4)	(4)	16,400	75,700	52,300
Webbers Falls (1) (3)	20,800	(4)	(4)	(4)	(4)	43,000
Eufaula	5,858	4,560	3,670	2,790	11,390	7,140
Keystone	6,373	4,130	3,290	1,990	16,800	12,410
Tenkiller Ferry	1,428	1,850	1,030	1,070	3,740	2,540
Fort Gibson	7,751	5,710	5,550	4,850	9,070	8,680

SWD Form 534-C
Rov 5 Jan 62

U.S. ARMY ENGINEER DIVISION, SWD Reports Control Symbol SWDGW-41

CORPS OF ENGINEERS

SUMMARY OF OPERATIONS

Dardanelle Hydro Plant Little Rock District Month of January, 1970

RESERVOIR OPERATIONS				
POOL EL. - BEGINNING MONTH			338.00	FT.
POOL EL. - END OF MONTH			336.89	FT.
	TIME	DAY		
MAX. ELEVATION	6 a.m.	5	338.01	FT.
MIN. ELEVATION	7 p.m.	21	336.27	FT.
AV. POOL ELEVATION			337.15	FT
AV. TAILWATER ELEVATION			288.29	FT.
AV. GROSS HEAD			48.86	FT.
ENDING USABLE POWER STORAGE			28,300	AC FT.
CHANGE IN STORAGE (or -)			-37,000	AC FT.
COMPUTED INFLOW			550,330	DSF
EVAPORATION			2,790	DSF
POWER DISCHARGE			565,530	DSF
FLOOD CONTROL DISCHARGE			0	DSF
TOTAL DISCHARGE *			566,040	DSF
MAX. DAILY DISCHARGE DAY 1			43,560	DSF
MIN. DAILY DISCHARGE DAY 31			4,630	DSF
% DISCHARGE USED FOR POWER			99.9	%
POT. POWER IN POWER DISCHARGE			56,092.5	MWH
PLANT EFFICIENCY			83.1	%
* Includes lock discharge of 510 DSF				
PRECIPITATION				
NO. DAYS OF RAINFALL			5	
MAXIMUM 6th DAY			.60	IN
TOTAL FOR MONTH			1.45	IN
YEAR TO DATE			20.01	IN
EVAPORATION				
MONTH				IN
YEAR TO DATE				IN

POWER PLANT OPERATIONS		
GENERATION IN MWH	THIS MONTH	THIS YEAR
HOUSE UNITS		
MAIN UNITS	46,603.0	348,236.0
GROSS GENERATION	46,603.0	348,236.0
STATION USE	317.0	1,922.2
NET GENERATION *	46,286.0	346,313.8
DELIVERED TO SPA	46,230.5	346,258.3
* Includes 55.5 for Navigation		
POWER RECEIVED (MWH)		
FOR CONDENSING	0	0
FOR STATION USE	317.0	1,922.2
TOTAL RECEIVED	317.0	1,922.2
STATION USE (MWH)		
FROM HOUSE UNITS		
FROM MAIN UNITS	317.0	1,922.2
FROM LINE	0	0
TOTAL STATION USE	317.0	1,922.2
DEMAND ON PLANT		
MAX. HOUR MWH 140	HOUR 1 a.m.	DAY 1st
MAX. DAY MWH 3,342		DAY 1st
PLANT SERVICE FACTORS (MAIN UNITS)		
LOAD FACTOR	44.4	%
CAPACITY FACTOR	50.2	%
AVAILABILITY FACTOR	100	%
TEMPERATURES		
MAXIMUM 29th DAY	77	OF
MINIMUM 8th DAY	7	OF

UNIT OPERATION

UNIT NO.	RATED CAPACITY KW	MWH GENERATED	GENERATOR USE & AVAILABILITY								MAX. HOUR MWH	UNIT SERVICE FACTORS	
			AVAILABLE		GENERATING		CONDENSING		UNAVAILABLE				
			HRS	MIN	HRS	MIN	HRS	MIN	HRS	MIN		LOAD	CAP
1	31,000	9,287	744	00	321	45	00	00	00	00	35	35.7	40.3
2	31,000	14,540	744	00	527	55	00	00	00	00	35	55.8	63.0
3	31,000	11,360	744	00	376	20	00	00	00	00	35	43.6	49.3
4	31,000	11,416	744	00	336	50	00	00	00	00	35	43.3	49.5
5													
6													
7													
8													
HU 1													
HU 2													
TOTAL	124,000	46,603			[illegible]	[illegible]					XXX	XXX	XXXXX

Figure 2

(1) Does not include leakage water.
(2) For period 1923 to 1967 and including the dry 1960's.
(3) For periods 1923 to between 1955 and 1960. At projects where both short and long period means are available the short-term means are larger than the means for the longer period.

(4) Releases as a percent of the mean flow are given below:

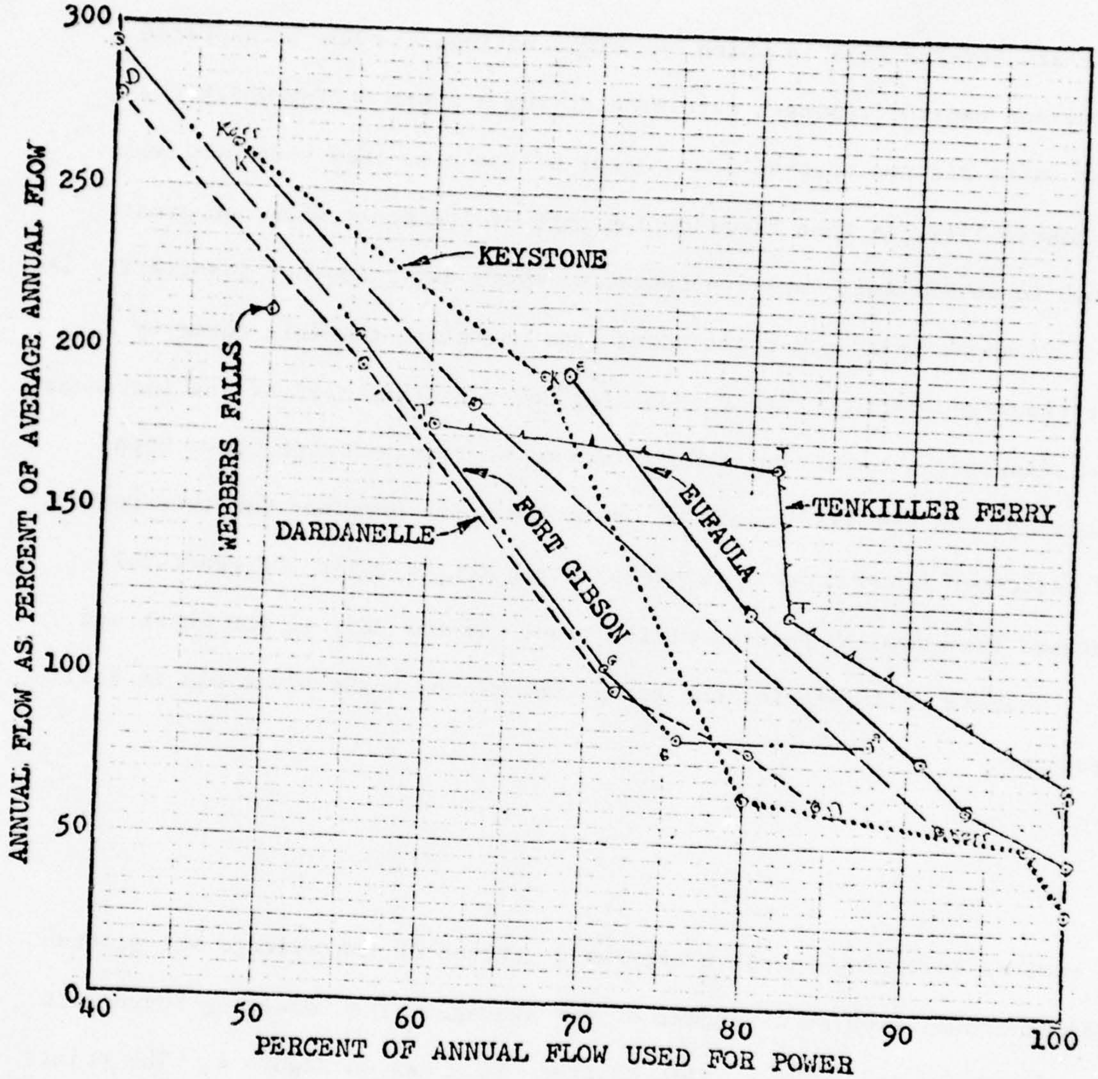
Project	Percent of Mean Annual Flow				
	1970	1971	1972	1973	1974
Dardanelle	98.5	79.4	63.9	276.4	195.5
Ozark				260.7	184.0
Robert S. Kerr			57.0	263.0	184.9
Webbers Falls					212.0
Eufaula	77.8	62.6	47.6	194.5	121.9
Keystone	64.8	51.6	31.2	263.6	194.7
Tenkiller Ferry	121.1	67.4	70.0	179.3	166.2
Fort Fibson	103.6	81.7	82.6	293.6	205.5

The above tabulation shows that 1970, 1971 and 1972 were generally quite dry years with significant variations from average run offs. The years 1973 and 1974, on the other hand, were very wet years. This tabulation also indicates that average discharges for a particular year in terms of a percentage of the mean can vary from drainage area to drainage area. For example, 1973 was a wet year at all eight projects, but the flow at Eufaula was only about twice average, while at Ft. Gibson the flow was about three times the average. The year 1970 was quite dry at Keystone; the flow being about 65 percent average, while at Tenkiller Ferry the flow was 121% of the average. In 1972, flows were below average at all projects, but at Keystone the flow was about 31 percent of the average, while at Fort Gibson it was about 83 percent of the average.

Energy. Another correlation was made as indicated on figure 3. The percentage of flow used for power generation during a particular year was plotted against the flow during the year expressed as a percent of the mean. The fact that points for a particular project do not fall on a curve, but rather in a band indicates that years of equal flow do not necessarily result in the same annual power generated at a particular project. The lower part of the trend line for Fort Gibson illustrates this very nicely. For about 82 percent of average flow, from 76 to 88 percent was used for power.

The reason for these aberrations is readily evident. For example, during one year, high average flows might result from very high flood flows of short duration, while during another year, moderately high flows can prevail during much of the year with only a few flood peaks. In the latter case, a larger portion of the total flow can be used to generate power.

A review of the data presented on the SWD Forms 584-C Summary of Operations, indicated numerous instances when flood control releases were made during months when the generators operated less than 100 percent of the time that they were available, i.e. not closed down for any reason. This suggests that some of the flood control release might have been passed through the turbines to generate more energy. To determine whether and how much additional energy is available, requires more detailed information and analysis than is available on these forms and more time than is available for this study.



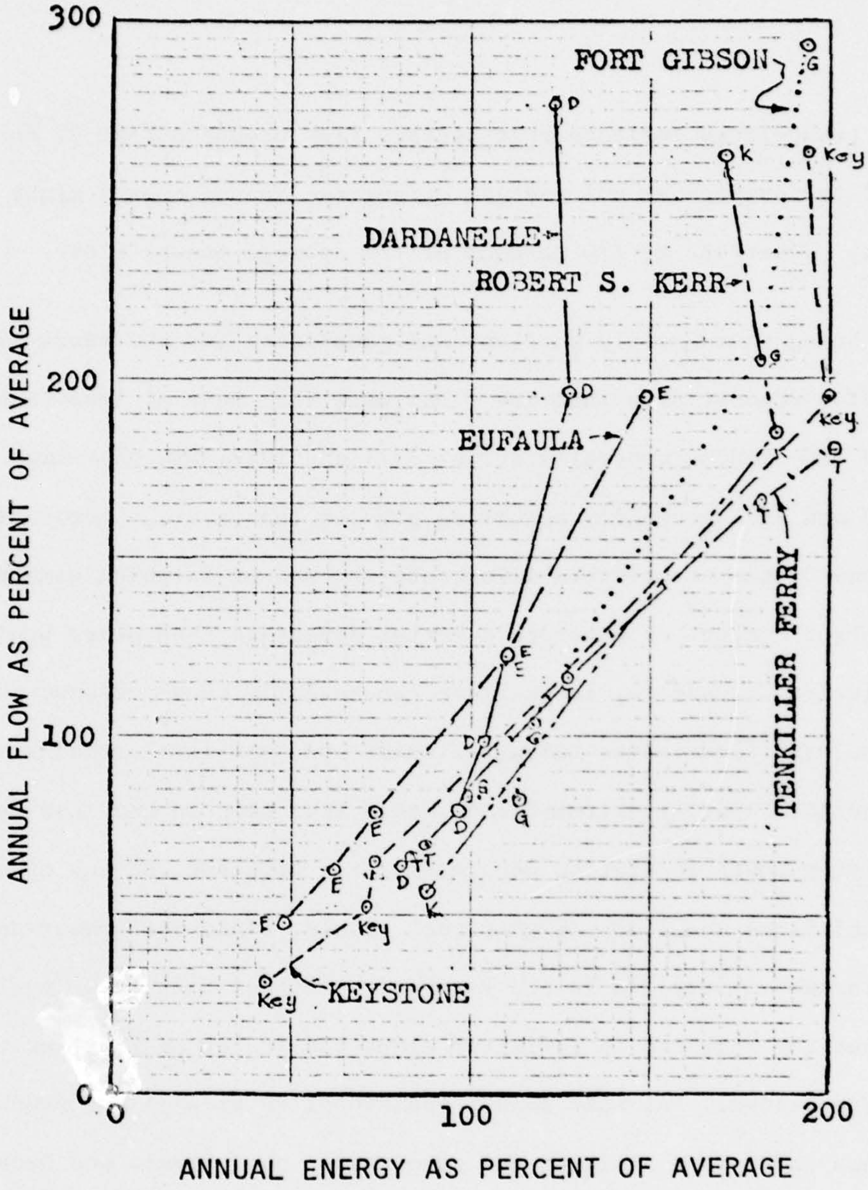
ANNUAL FLOW vs.

PERCENT OF FLOW USED FOR POWER

Figure 3

There are several ways in which one might rationalize how it happened that flood control releases were made during a month during which the power units did not operate 100 percent of the time they were available. One possibility, is that flows during part of the month were not great enough to permit full capacity operation every day. Another possibility is that SPA might have been constrained from marketing the full capacity continuous generation. It is probable, however, that most of the instances under discussion could represent a loss of energy that might have been generated. Of the 385 Summary of Operation Forms examined for this report, 118 indicated flood control releases during months while the generators operated less than 99 percent of the time. Of the 385, 12 for Ozark and 4 for Webbers Falls are for the period before the power plant was in full operation.

In another analysis, annual energy as a percent of the average was plotted against annual flow as a percent of the average. The resulting curve with data for Ozark and Webbers Falls omitted, is shown on figure 4. The points for each project plot along a well defined trend-line, but none of the trend-lines pass through the points where average flow yields average energy. The trend-line for Dardanelle comes nearest to this point with 100 percent average annual flow producing about 104 percent annual energy, or, stated in another way, about 90 percent of average-annual flow produced average-annual energy.



ANNUAL ENERGY VS. ANNUAL FLOW
AS PERCENT OF AVERAGE

Figure 4

The other trend-lines indicate that average flow produced from 92 to 120 percent of the average annual energy, or average annual energy might be produced by 72 percent to 110 percent of the average annual flow.

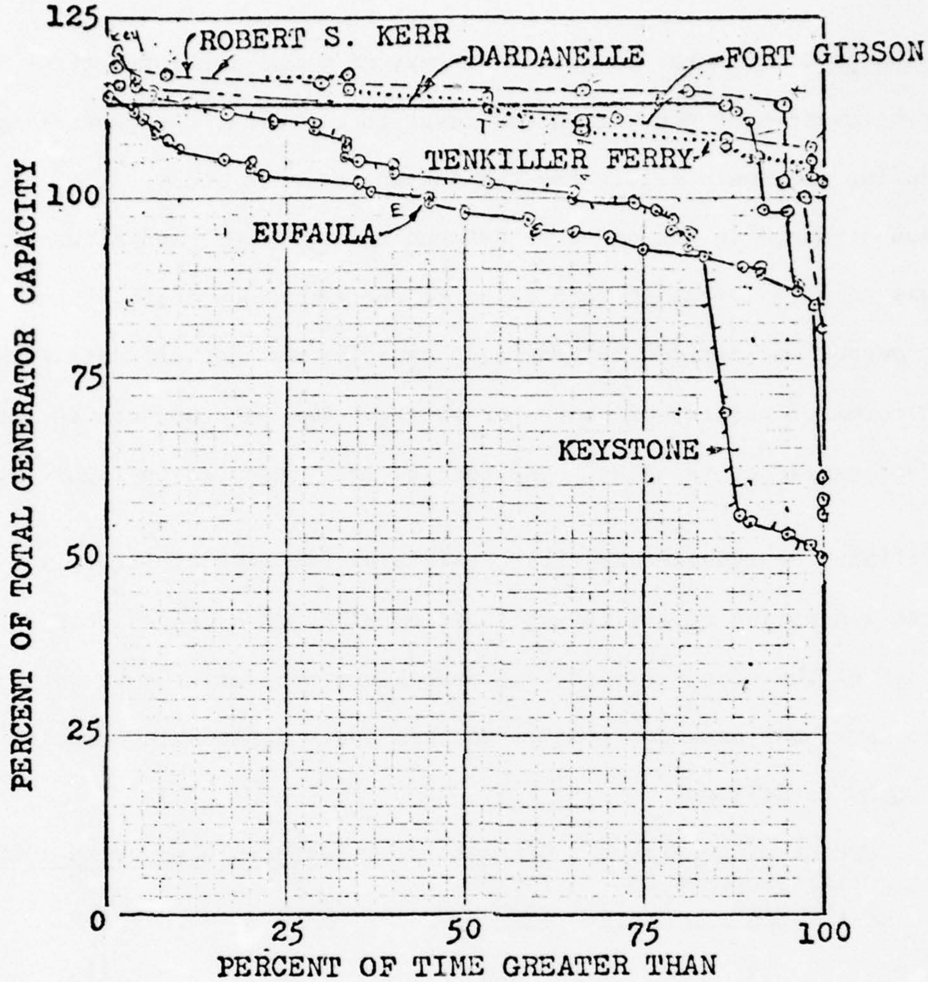
Figure 4, being based solely on flows and generation for the years 1970 through 1974, demonstrates that low flows were the cause of less than average generation experienced generally during 1971 and 1972, and that high flows as in 1973 and 1974 generally result in greater than average generation. The portions of the trend-lines illustrate the manner in which some projects can use larger amounts of water to a better advantage than other projects. For example, at Dardanelle, large flows can actually cause reduced generation because the high flows raise tailwater while the pool level remains essentially constant. During extreme floods, this reduction in head can be great enough to stop power generation completely. At Keystone, on the other hand, large annual flows would mean higher pool levels, since both power and flood control storage is provided in the reservoir. Higher tailwater levels also prevail, but the increase in tailwater elevation is not as large as the increase in pool level. At some point, additional water will not produce more energy since there is a limit to the permissible pool level, and because the turbine output is mechanically limited to about 115 percent of the name-plate generator capacity. These and other factors account for the more or less vertical upper legs displayed by the trend-lines for Dardanelle, Eufaula, Robert S. Kerr, Fort Gibson, and Keystone.

Dependable capacity. From the completed Summary of Operation Forms the maximum-hour kilowatt-hour generation was taken to represent the generating capability during the month solely for the purpose of this study. The data were then arranged in the order of descending magnitude, and a duration curve was computed assuming each value to represent one month. The maximum-hour output was divided by generator capacity so that all data were expressed in terms of percent of generator rating. The data so derived was plotted on rectangular coordinates. The results are presented on figure 5.

One way of defining dependable capacity consists of assuming arbitrarily that it is the generating capability which is equalled or exceeded some high percentage of the time. For the Arkansas River project, the value is understood to have been assumed as 95%. On this basis dependable capacity might be computed as follows:

Project	Percent of generator rating exceeded 95% of the time	Generator rating 1000 kw	Dependable capacity 1000 KW	
			This method	CE value
Dardanelle	95	124	118	124
Ozark (1)				
Robert S. Kerr	113	110	124	100
Webbers Falls (1)				
Eufaula	87.5	90	79	88
Keystone	53 (2)	70	37	70
Tenkiller	105	34	36	28
Fort Gibson	107	45	48	45

(1) Ozark and Webbers Falls have been omitted because they were not in full operation during the entire period of study.
(2) For five months, four of them consecutive, one generator or the other was out of service. If this constituted a scheduled overhaul period which should not be included in the determination of dependable capacity, then dependable capacity is 68% of generator rating or 48,000kw.



PERCENT OF TIME GREATER THAN VS.
PERCENT OF GENERATOR CAPACITY

Figure 5

The above analysis is based on only five years of operating records and consequently may not represent truly average conditions. If further study based on a longer period of record indicates similar differences between values for dependable capacity, further examination to determine the cause may be warranted. It may be that the projects are not operated in exactly the same manner as originally planned.

The individual hydropower projects in the SPA system are operated on the basis to fill the requirements of SPA load. How this is done was examined briefly on the basis of the "maximum hourly generation" from the SWD Summary of Operations forms, and a SPA "Monthly Production Report" for December 1975. The latter report lists power projects in three groups, the largest of which contains 16 projects including the eight studied for this report. The other eight are Beaver, Broken Bow, Bull Shoals, Denison, Greers Ferry, Norfork, Stockton, and Table Rock. The report lists the same values for "maximum hourly generation" as the SWD Summary Reports, and for the 16 projects, the values for the individual projects total 1.699 million kilowatts. In comparison the "hydro contribution to peak interconnected system load" from the same 16 projects was given as 1.295 million kilowatts. Obviously, the load was such that all 16 plants did not need to peak at the same time.

The "maximum hourly generation" at all plants could be scheduled to occur at the same time, and, accordingly, the sums of the "maximum hourly generation" values for the eight plants studies in this report and the other eight plants in the interconnected system could serve as an index of what

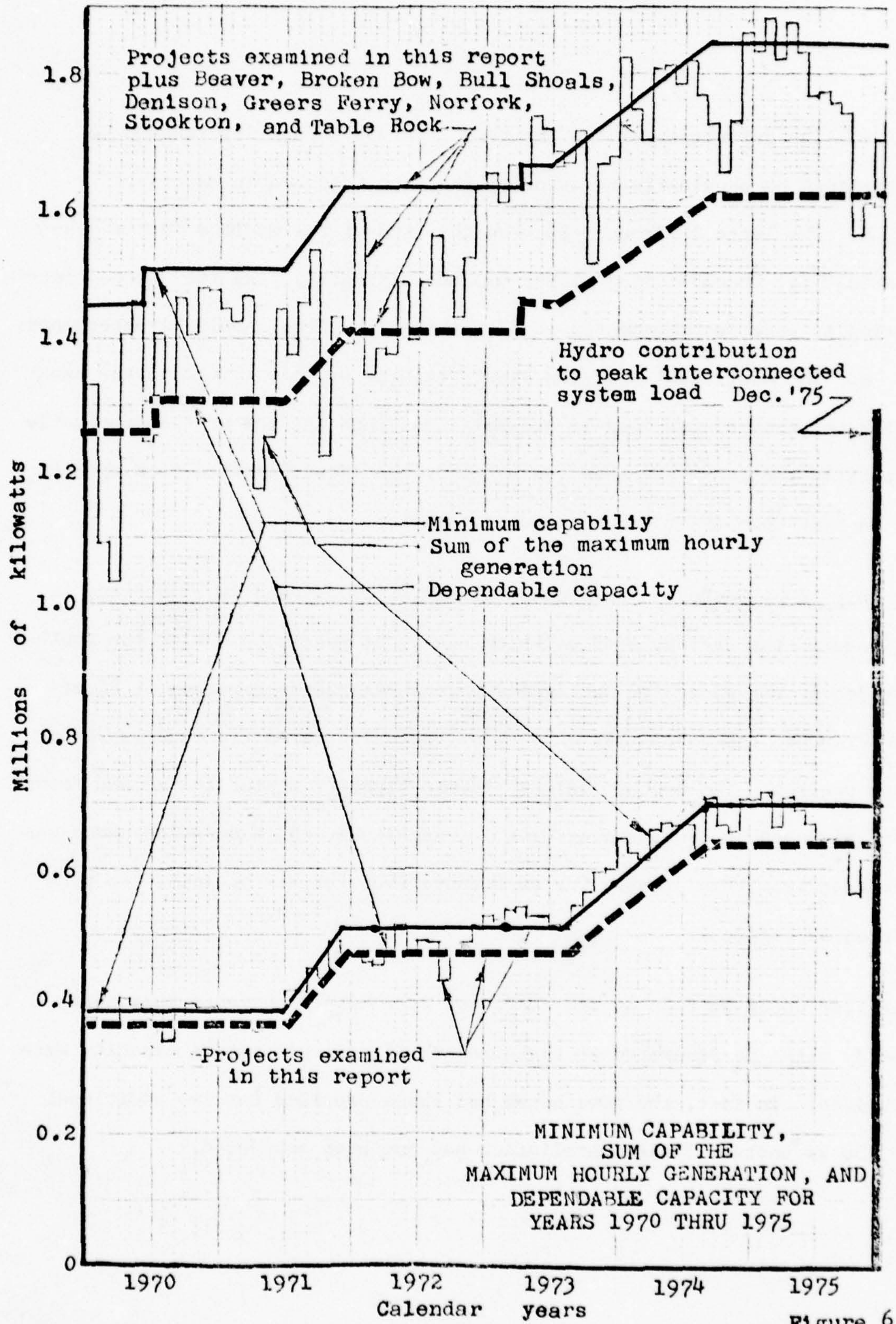
the projects are capable of in serving load as far as capacity is concerned. A full analysis would require the simultaneous consideration of energy as well as capacity to meet the requirements of the system load. This full analysis was not undertaken because a large amount of additional work would be required. The results of the analysis of the sums of maximum hourly generation is shown on figure 6. The monthly sums for the eight plants of this report and of the 16 plants in the interconnected system are shown for the years 1970 through 1975, and are compared with the "dependable capacity" and the "minimum capability" prevailing during the period of study, and the "hydro contribution to peak interconnected system load" for December 1975. "Dependable capacity" for the various projects was taken from the "power project data sheets" and the "minimum capability" values are from the SPA report of December 1975. The figure indicates the following:

a. The sums of dependable capacity, minimum capability and maximum hourly generation grew through most of the 1970-1975 period.

b. The sums of maximum hourly generation are generally greater than the sums of dependable capacity for both the eight and the 16 plants.

c. The hourly sums, where less than the sum of dependable capacities, may be the result of market conditions rather than generating capability.

d. In view of the foregoing, both the eight projects of this report and the 16 projects serving the interconnected load probably could have met the capacity requirements of system load amounting to the sums of the dependable capacities of the individual projects during the period examined. How well the energy requirements of such a load would be served by the 16 plants is not known.



Projects examined in this report plus Beaver, Broken Bow, Bull Shoals, Denison, Greers Ferry, Norfork, Stockton, and Table Rock
Hydro contribution to peak interconnected system load Dec.'75
Minimum capabiliy
Sum of the maximum hourly generation
Dependable capacity
Projects examined in this report
MINIMUM CAPABILITY, SUM OF THE MAXIMUM HOURLY GENERATION, AND DEPENDABLE CAPACITY FOR YEARS 1970 THRU 1975
Millions of kilowatts
0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
1970
1971
1972
1973
1974
1975
Calendar years

Figure 6

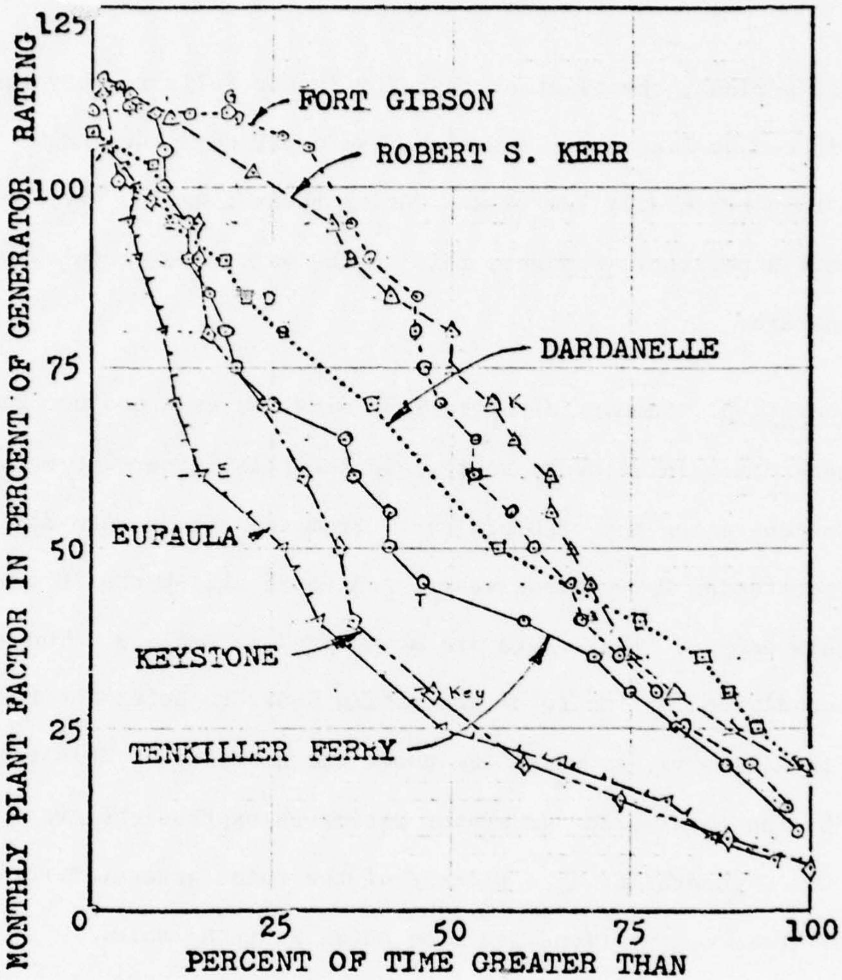
e. The definition of the SPA term "minimum capability" should be determined as should its relation to the term "dependable capacity."

f. The large difference between the "sum of the maximum hourly generation" for December 1975 (1.699 million kilowatts), and the "hydro contribution to peak interconnected load" for the same date should be determined.

g. The contribution of the eight projects of this report to the peak interconnected system load is probably less than the sum of the dependable capacities, but only because the total system interconnected load appears to be less than the total dependable capacity.

Monthly plant factor. The monthly plant factor as used in this study is defined as the average rate at which energy is generated during the month divided by the generator rating and then expressed as a percent. Plant factors were taken from SWD Summary of Operation Forms for each month for each project. The monthly values (termed capacity factor in the SWD Forms) were arranged in a descending order of magnitude, and a duration curve was prepared from this array. The duration curves for six projects are presented as figure 7.

The flat upper portion of the curve for Fort Gibson suggests that more energy might be generated at that project if more generating capacity were provided. In fact, the powerhouse has space provided for two additional 11,250 kw units. Their installation has not been scheduled.



NOTE: The monthly plant factor is the average generation during the month divided by the generator rating and expressed as a percent.

MONTHLY PLANT FACTOR vs. PERCENT OF TIME GREATER THAN

Figure 7

During low-flow periods, the plant or capacity factor falls to very low values as indicated by Figure 7. The plant factor at Keystone and Eufaula falls to particularly low values during these low-flow periods, that is to about 6 percent. However, this is the way these projects were designed to operate.

Power plant operation. Summary of Operation Forms for each project gave the monthly generation in kilowatt hours, and the total time that each power unit was generating for each project. From these data were derived total annual generation for various years, and total unit-hours it took to generate this energy. These data are summarized in Table 3. The annual energy was then divided by the total generating hours to determine the average rate in kilowatts, at which the power was generated. This value was then divided by the total plant generator rating to express the average generating rate while generating as a percent of the total generator rating. The results of these computations are also shown in this table.

The average generating rate while generating is very nearly the generator rating, in fact, the average of all full-year generation data is about 99.0 percent of the total generator rating. Ozark was omitted because the record forms indicated that the project had not attained normal operation even though two years of operating record were available on SWD Forms 584C.

TABLE 3
Average Plant Output While Generating

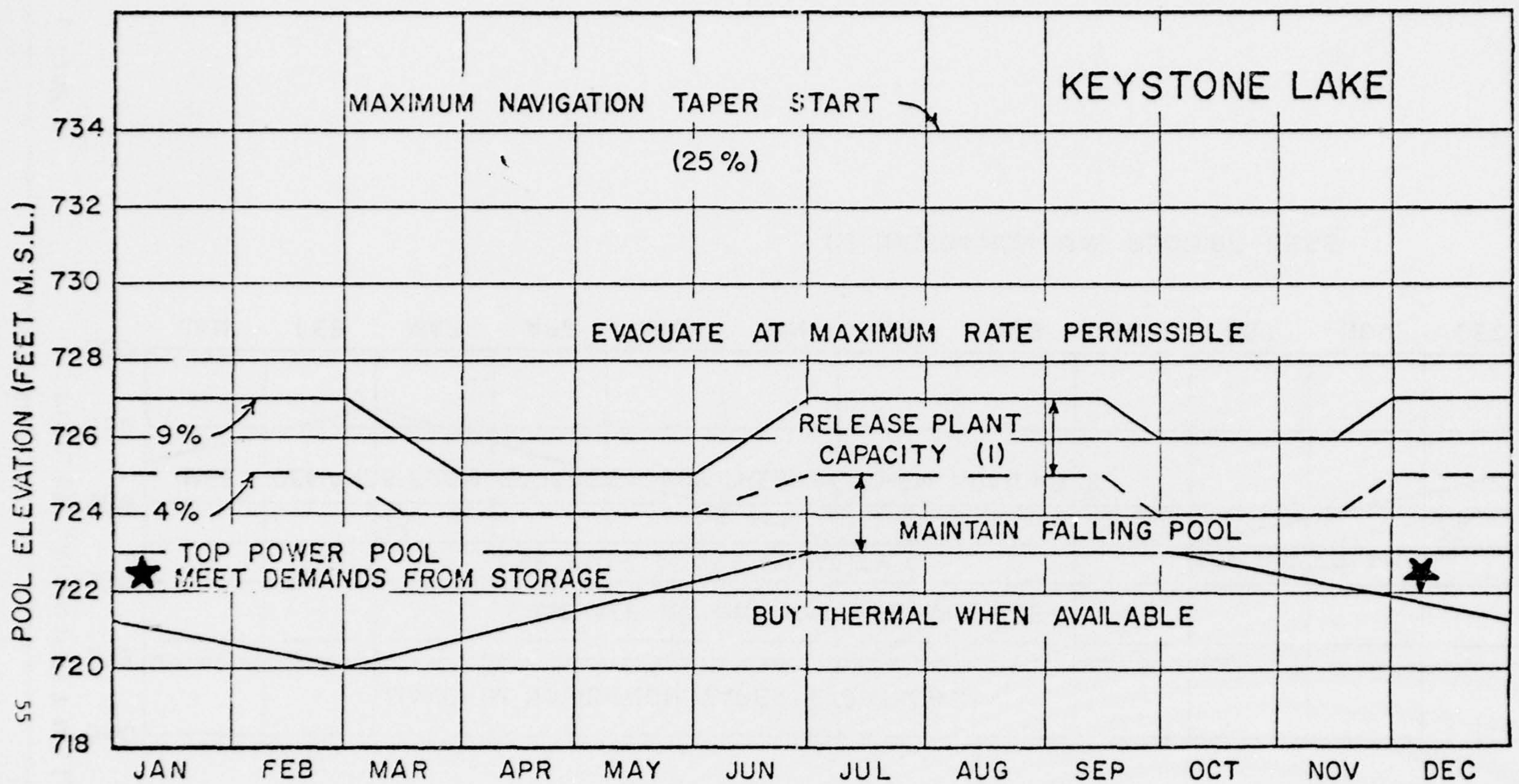
Project	Avg	Calendar year 1970	1971	1972	1973	1974
Dardanelle (4 @ 31,000kw)						
Energy 10^6 kwh/yr.		634.6	689.8	498.2	759.5	878.7
Time, 10^3 hours generators operated (1)		19.5	20.0	16.8	28.8	29.7
Ave. power while generating, 10^3 kw		2.5	29.5	29.7	26.3	29.6
Ave. as % of generator rating	95.2	104.8	95.2	95.9	84.9	95.4
Ozark (5 units @ 20,000 kw) (2)						
Energy, 10^6 kwh/yr					28.7	353.4
Time, 10^3 hrs, generators operated (1)					2.8	20.7
Ave. power while generating, 10^3 kw					10.0	17.1
Ave. as % of generator rating					50.0	85.3
Robert S. Kerr (4 units @27.500 kw)						
Energy, 10^6 kwh/yr				405.7	783.8	849.1
Time, 10^3 hrs., generators operated (1)				14.6	29.1	29.6
Ave. power while generating, 10^3 kw				27.9	26.9	28.7
Ave as % of generator rating	101.2			101.4	97.9	104.3
Webbers Falls (3 units @ 20,000 kw)						
Energy, 10^6 kwh/yr						373.4
Time, 10^3 hrs., generators operated (1)						19.9
Average power while generating 10^3 kw						18.8
Ave. as % of generator rating	93.7					93.7
Eufaula (3 units @ 30,000 kw)						
Energy, 10^6 kwh/yr		233.8	193.4	156.4	472.2	348.3
Time, 10^3 hrs., generators operated (1)		8.6	7.3	5.9	15.7	11.7
Average power while generating, 10^3 kw		27.2	26.5	26.7	30.1	99.1
Average as % of generator rating	98.4	95.0	94.9	93.5	104.3	104.2
Keystone (2 units @ 35,000 kw)						
Energy 10^6 kwh/yr		167.5	160.5	97.5	442.4	454.3
Time, 10^3 hrs., generators operated (1)		5.0	4.8	3.0	12.1	12.5
Average power while generating, 10^3 kw		33.2	33.2	32.7	36.5	36.5
Average as % of generator rating	98.4	95.0	94.9	93.5	104.3	104.2
Tenkiller Ferry (2 units @ 17,000 kw)						
Energy, 10^6 kwh/yr		145.1	95.2	99.8	230.1	206.8
Time 10^3 hrs., generators operated (1)		8.4	5.7	5.9	12.4	11.6
Average power while generating 10^3 kw		17.3	16.8	17.0	18.6	17.8
Average as % of generator rating	102.9	101.6	98.7	99.9	109.3	104.9
Fort Gibson (4 units @ 11,250 kw)						
Energy, 10^6 kwh/yr		222.8	216.0	189.2	367.0	343.0
Time, 10^3 hrs., generators operated (1)		18.5	17.8	15.6	29.7	27.7
Average power while generating, 10^3 kw		12.1	12.1	12.1	12.4	12.4
Average as % of generator rating	108.5	107.2	107.6	107.7	110.0	110.0
AVERAGE	99.0	100.7	96.9	97.9	101.2	100.8

(1) Total unit-hours, 10^3, generators were on line.
(2) Not included in averages.
Note: Average plant output in Kilowatts while operating.

The inference drawn from the above statistic is that each of the 27 generating units is fitted into the daily load curve very carefully, that each unit comes on the line and is taken off the line at times which fulfill two requirements, i.e., meet the power demand and use the amount of water available for the day. This seems to be accomplished well, since the record shows a minimum of "wasted" water, i.e., releases other than those made during obviously flood period.

Reservoir operating rules. The reservoirs considered in this report are operated in accordance with a system of regulations that prescribe flows according to the season and other factors. No attempt was made for this report to evaluate the regulations as they relate to the generation of power. The following figures 8 and 9 illustrate some of the applicable regulations at Eufaula and Keystone projects.

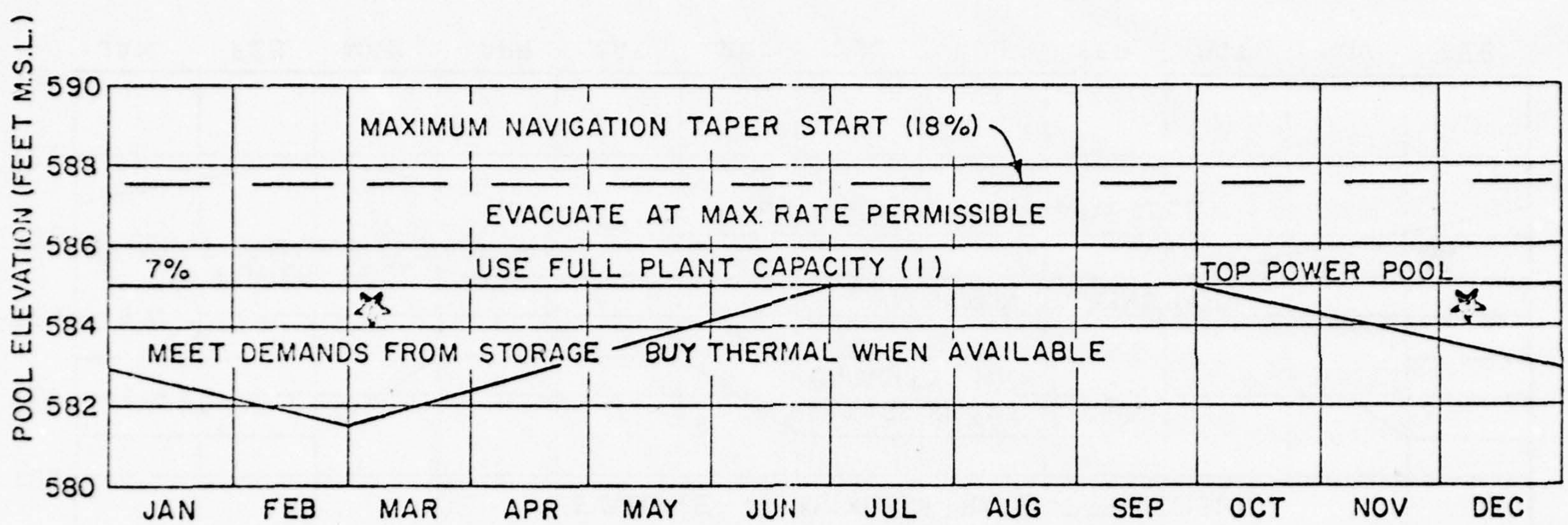
Generating history. SPA monthly production reports contain data on annual generation of all Corps power projects in the SPA system extending back to the year each plant was placed in operation. Table 4, data for which was extracted from the December 1975 SPA report, shows annual generation for each of the projects examined. Mean annual generation is also shown for each project. Although obviously partial years were excluded from computing the mean generation, other, not so obvious, partial year records may still influence the mean. Below the mean for each project is shown the estimated average generation used on the Power Project Data sheets. Below the latter is presented the ratio of the mean to the estimated average.



(1) A SMALLER GENERATION MAY BE REQUIRED FOR NAVIGATION

Figure 8

EUFAULA LAKE



(1) NAVIGATION MAY REQUIRE LESS

Figure 9

TABLE 4

Net Generation from Power Projects by years, 1953 — 1975

1,000,000 kwh

Calendar Year	Main stem projects: Darda-nelle	Ozark	Robert S. Kerr	Webbers Falls	Upstream projects: Eufau-la	Key-Stone	Trib. projects: Ten-Killer Ferry	Fort Gibson	Total 8 projects
1953							10.4 (1)(5)	41.1	51.5
1954							51.7	45.9	97.6
1955							57.7	107.4	165.1
1956							25.6	35.3	60.9
1957							106.3	113.2	219.5
1958							118.9	184.1	303.0
1959							105.3	197.9	303.2
1960							106.6	227.3	333.9
1961							149.8	308.5	458.3
1962							96.8	236.1	332.9
1963							27.6	63.0	90.6
1964					4.4 (1)		30.9	74.9	110.2
1965	190.3				78.6		65.6	172.3	506.8
1966	295.3				89.9		79.4	105.7	570.3
1967	424.2				59.0		28.3	177.6	689.1
1968	669.2				228.0	144.0	144.9	286.5	1472.6
1969	733.8				320.4	271.4	140.6	323.3	1789.5
1970	634.6				233.8	167.5	145.1	222.8	1403.8
1971	589.8		197.9 (5)		193.4	160.5	95.2	216.0	1452.8
1972	498.2		405.7		156.4	98.0	99.8	189.2	1447.3
1973	759.5	28.6 (1)(5)	783.8	67.5 (1)(5)	472.2	422.2	230.1	367.0	3130.9
1974	878.7	353.6 (5)	849.1	373.4	348.3	454.3	206.8	343.03	3807.2
1975	734.4	469.5	703.7	318.3	398.9	355.4	170.3	264.5	3415.0
No. of yrs	11	2	5	2	11	8	22	23	
Mean(2)	583	412	608	346	234	259	104	187	2733
Est.(2)(3)	613	429	459	213	317	228	114	190	2563
Ratio (4)	0.95	0.96	1.32	1.62	0.74	1.14	0.91	0.98	1.064

(1) Not included in computation of averages.
(2) In millions of kwh/yr.
(3) From power project data sheets; 1973, 1974.
(4) Mean/Est.

Note: Generation values in this table are for calendar years and differ from other tables in this report which are on fiscal year basis.

The ratios range from 0.74 for Eufaula to 1.62 for Webbers Falls. Except for Eufaula, the projects with the longer generation records have ratios of 0.91 to 0.98. The projects are Fort Gibson, Tenkiller Ferry and Dardanelle. Ozark also has a ratio in this range, 0.96, but its record includes 1974, a high water year during which the project was not completely in operation. Had the plant been in full operation, its ratio would have approximated those of the Robert S. Kerr project with a ratio of 1.32 and Webbers Falls project with a ratio of 1.62. The high ratios of the latter two plants results from the fact that the generating record is dominated by years of relatively high flows, 1973,1974 and 1975.

Eufaula, with a ratio of 0.74, presents an interesting contrast with Keystone with a ratio of 1.14. The difference in ratios is apparently due to the relatively dry years 1965, 1966, 1967 which occurred right after Eufaula was placed in operation, but which has not reoccurred since the time Keystone was placed in operation. Examination of the last column, total generation through the years as the number of plants on-line increased from two in 1953 to eight in 1975, presents an interesting overview. The year 1970 shows reduced generation from the previous year undoubtedly caused by decreased flows. The years 1971 and 1972 showed very little improvement despite the addition of Robert S. Kerr. These were quite dry years. However, in 1973, increased flows permitted the 8-plant system to generate at a rate about 22 percent greater than the estimated rate despite the fact that Ozark and Webbers Falls operated only during a small part of the year.

This trend continued through 1974 and 1975 when generation at the eight plants was 48 and 33 percent greater than original estimates. In 1974, all plants, except Ozark which was not in full operation, produced more energy than the estimated average. In 1975, all eight plants produced more than the estimated average for each plant. Figure 10 is a plot of the ratio of mean actual generation to the originally estimated generation vs. the number of years of record with upper and lower enveloping curves. The figure shows, as one would expect, that the enveloping curves approach a value near one with increasing number of years of record. The fact that the enveloping curves seem to approach a value somewhat less than one may or may not be significant. There are not enough data points in the plot to make a fine distinction. The data do seem to indicate that the original estimates are probably quite good, possibly within 5 percent, or better.

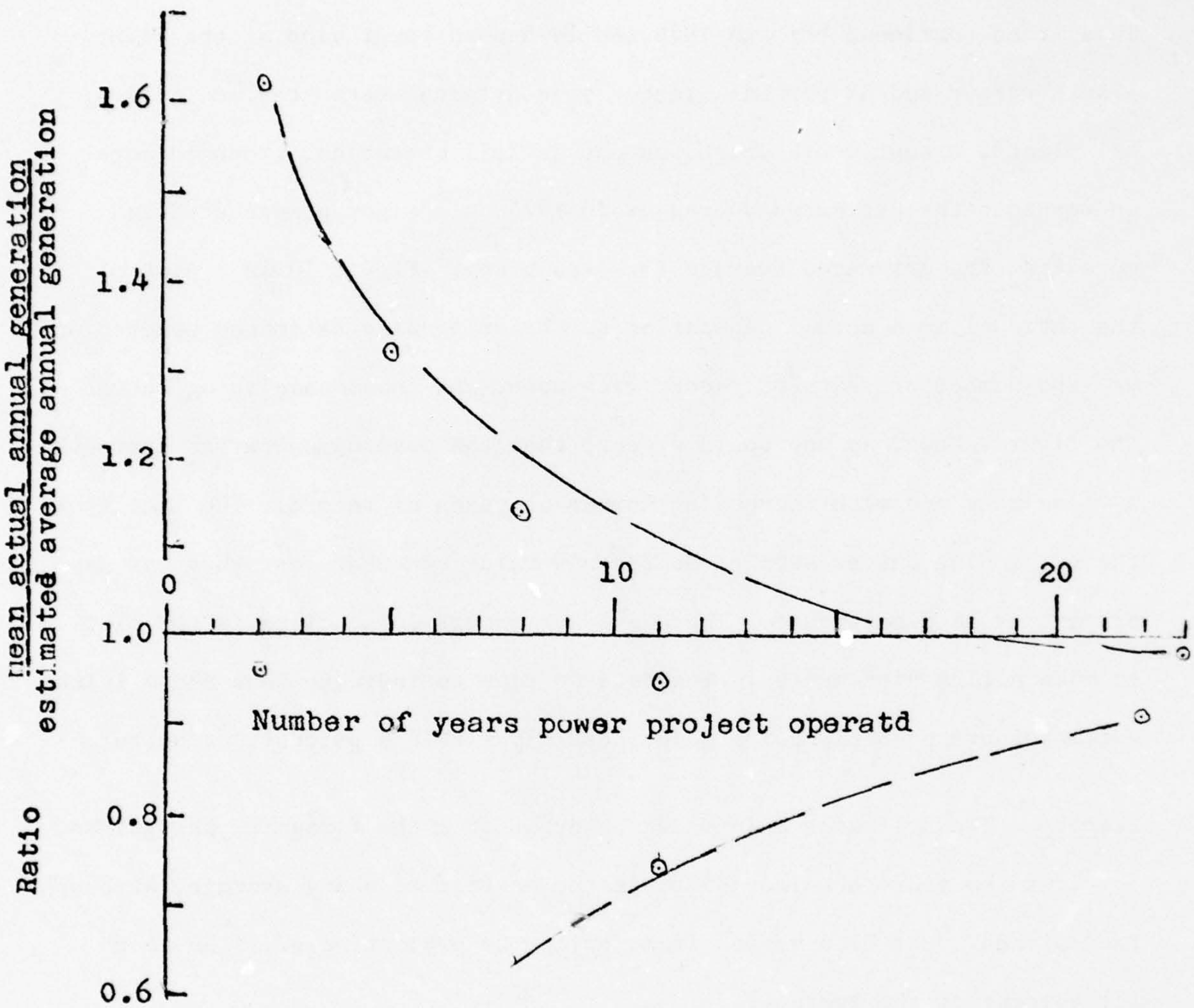
Summary. The following points can be drawn from the foregoing paragraphs.

. Of the years studied, 1970 was the nearest to being average, although the calendar-year flow varied from project to project, e.g., from 65 to 121 percent of the average.

. 1971 and 1972 were very dry years, and power generation was below the estimated.

. 1973 and 1974 were very wet years. In 1973, Fort Gibson passed almost three times the average flow.

. An increase in annual flow increases the amount of flow that can be used for power, but generally the percentage of the total flow that can be used for power decreases.



RATIO,MEAN ACTUAL GENERATION TO
ESTIMATED ANNUAL GENERATION VS.YEARS POWER
PLANT HAS BEEN IN OPERATION

Figure 10

. In the year 1970 generation of the plants studied decreased from the previous year, presumably because flows decreased.

. In 1971, flows decreased and generation at Arkansas River project power plants remained low in spite of the addition of the Robert S. Kerr project to the system during the year.

. Flows decreased further in 1972, and system generation remained static in spite of full time operation of the Robert S. Kerr power plant.

. The trend of low flows and low generation ended in 1973 when flows and generation essentially doubled over the previous year.

. The high flows and high generation continued in 1974.

. Generating data indicates that high generation extends through 1975.

. Generation for 1973, and 1974 exceeded the originally estimated average generation for all eight projects even though the Ozark project was not in full operation during all of 1973 and 1974, the Webbers Falls project was only in partial operation during 1974.

. It may be possible to increase generation during high flow years. At Fort Gibson, additional power units could accomplish this. At other projects, changes in the operating rules may be possible for this purpose.

. Data on actual generation are not extensive enough to determine conclusively whether the average generation used for economic studies was accurate. Trend studies seem to indicate, however, that the original estimates were reasonably accurate.

. For the short period examined, dependable capacity values for the projects studied appear inconsistent. Examination of a longer period of

operation may show dependable capacity to be closer to the originally estimated values. If not, further study might be warranted as to the cause.

. Duration curves of monthly plant factor (average monthly rate of generation divided by total generator rating, expressed as percent) show a wide variation among the projects considered. They all peak in the range of 105 to 115 percent. Only one, that for Fort Gibson, shows a flat top indicative of less than complete development of the site. At the lower end, the curves bottom at 6 to 20 percent monthly plant factor. Eufaula and Keystone showed the lowest curves and Fort Gibson and Robert S. Kerr the highest.

. The power plants generated power only part of the time as intended. The percent of the time during the month that each project generated power was roughly proportional to the amount of water available for that purpose. When generating, the power units operated at about the generator rating.

. The type of operation described above is essentially a peaking operation, with each unit moving up and down on the load curve as appropriate to use available water.

POWER MARKETING FUNCTIONS.

<u>Introduction</u>. Section 5 of the Flood-Control Act of 1944 requires coordinated operations by Southwestern Power Administration (SPA), the Corps of Engineers (SWD in this case), and Federal Power Commission (FPC) in conjunction with the operation of multi-purpose projects with power. These operations are discussed in the following paragraphs.

SPA operations. SPA receives the power generated at Corps projects at the high voltage side of the switch yard, transmits it over a transmission system that includes some lines owned by SPA, and delivers it to customers, who, in turn, pay SPA for the power. From the revenues collected each year, SPA pays its own costs such as payroll, office costs, interest on investment, amortization of debt, and so forth. The remainder is sent to the Treasury as miscellaneous receipts as required by the 1944 Flood Control Act. SPA informs the Corps of Engineers of the gross amount of this remainder. The Corps uses this remainder to keep a running account of the recovery of costs allocated to power at each project. Details of SPA operations as they pertain to SPA customers are discussed in the following paragraphs. Most of the following information may be found in IWR review draft dated November 1974, subject: "Reevaluation of Hydropower Potential at Corps of Engineers Projects."

SOUTHWESTERN ELECTRIC POWER COMPANY

The SPA contract with Southwestern Electric Power Company (SWEPCO) serves the full load requirements of SPA's preference customers. SWEPCO integrates power from Corps projects with its thermal power and delivers it at a normal load factor to SPA preference customers. SWEPCO pays according to the P-2 rate for primary energy (1800 Kwh/kw annually). For the firming power SPA pays SWEPCO according to SWEPCO's regular rates \$1.65/monthly kw and 3.0 mills per kwh. The latter charge is subject to a fuel supplement. The preference customers pay SPA according to the F-1 schedule.

The net effect of the above arrangements was a deficit estimated in 1970 at $32,000. To recover the losses noted above, SPA revised its energy charge for the P-2 schedule from 2.0 to 2.9 mills/kwh. When FPC approved the new rate SWEPCO cancelled its contract with SPA.

PUBLIC SERVICE COMPANY AND OKLAHOMA GAS-ELECTRIC COMPANY

The SPA contract with the Public Service Company of Oklahoma and Oklahoma Gas-Electric Company (Oklahoma companies) is similar to the contract with SWEPCO; however, among other differences, SPA charges $1.60 per monthly kw and 3.5 mills per kwh. Also the Oklahoma companies may purchase interruptible capacity in addition to peaking power and excess energy according to the 1C rate schedule. During 1970 SPA incurred about $800,000 in losses in this contract, and proposed to add a 1.4-mill/kwh "service charge component" to the P-2 rate. FPC approved the increase in 1971, but implementation was delayed pending the Associated case (discussed below) decision in the courts.

ASSOCIATED ELECTRIC COOPERATIVE

In 1962, SPA signed contracts with Associated Electric Cooperative, Inc., an association of six REA cooperatives and with three private utility companies. The contract provided that SPA would supply 288,000 kw and 345.6 million kwh of annual firm energy at the P-2 peaking power rate. In addition, supplemental energy may be supplied to Associated at 2.0 mills/kwh. Power is delivered by transmission lines owned by Associated. For use of

these lines and other services such as providing reserve generating capacity, Associated is given an annual credit which is subtracted from the amount due SPA. This credit almost equalled the revenues due SPA, for example, between 1962 and 1969 SPA received $34.4 million from Associated and paid $30.4 million to Associated for various credits.

To reduce deficits SPA imposed a $2,647,100 annual transmission service charge. FPC approved the charge on 28 May 1970, but implementation has been delayed pending a decision by the U.S. Court of Appeals.

SPA's contract with the three private utilities provides for supplying 192,000 kw and 1200 kwh annually for each kw according to the P-2 schedule. The contracts between Associated and the private companies provide for interconnection of transmission systems and pooling of SPA peaking hydropower.

ARKANSAS POWER AND LIGHT COMPANY

A 30-year SPA contract expiring on 21 December 1983 with the Arkansas Power and Light Company (AP&L) provides for the sale of 150,000 kw with 2,400 annual kwh per kw, plus 25 million kwh per month of excess energy. AP&L in turn delivers 110,000 kw of high load factor power to Reynolds Metal Company (a defense industry) at Arkadelphia, Arkansas. The initial rate was 1.25 mills/kwh during which could be increased to 2.0 mills/kwh during the last 10 years of the 30-year contract.

IWR Appraisal. The marketing practices of SPA have been reviewed numerous times. The following appraisal appeared in the IWR review draft of November 1974, entitled: "Reevaluation of Hydropower Potential at Corps of Engineers Projects." The appraisal starts with a statement that of all Federal power marketing agencies, SPA's financial performance was the worst. By 1973, the cummulative deficit had reached $15 million, but since then the deficit has declined because of favorable water flow conditions and the 1970 rate adjustments.

GAO (quoted in the IWR report) identified the main reasons for SPA deficits as the contract provisions for (a) excessive and inequitable credits to customers for performing services for the government, (b) sale of power to support a defense industry (Presumably Reynolds Metals), (3) SPA's purchase of off-season power which it was not able to market.

The 1970 rate adjustments and the introduction of the annual transmission charge contributed significantly towards offsetting the unfavorable clauses. However, in the case of certain contracts the issue of their legality is still pending in the courts.

A revision of SPA rate schedule and a change in marketing policies may be needed, according to the IWR report, rather than the offsetting charges noted above. In addition to exchanging high-value peaking-power for lower value high-load factor power, SPA also had to pay the utilities according to rates according to the higher thermal generation costs. As the SPA system can supply 2200 kwh per kw during an average year and 1200 kwh per kw during a dry year, it would be more economical to contract for peaking

sales with an annual 1200 to 1800 kwh per kw than firm service that may require an annual 4400 kwh per kw which requires purchasing firming energy.

SPA also could revise its rate levels between the various schedules, according to the IWR report. For example, the capacity charge for peaking service is 25 percent less than the corresponding charge for firm service. Also, peaking energy is valued at only a slightly higher rate than excess energy, and at the same rate as for energy with interruptible capacity service, and substantially less than for energy with firm service. Since the value of energy, especially peaking energy, is increasing because of increasing fuel costs, SPA has a strong reason to revise its rates to reflect more realistically the economic value of the power service supplied.

Instead of offering discounts for substation services, it would be simpler for SPA to sell power at the primary (high) voltage side of the switchyard and to add charges for providing additional services according to the cost of the services.

The IWR report summarizes SPA's marketing weaknesses as (a) contracting to market "firm power" in quantities greater than that produced (and estimated for production) by these projects, (b) the unfavorable marketing arrangements in which SPA ends up paying the difference in cost between thermal and hydropower generated, (c) rate levels which are not related to the economic value of the peaking service supplied, and (d) discount policies which result in poor economic returns from the sale of power.

Corps of Engineers activities. The Corps operates the reservoirs considered in this report, in accordance with the requirements of navigation, flood control, power, and other purposes. Power requirements are established by the SPA, and the Corps operates the powerhouses accordingly unless flood control or other emergency situations dictate otherwise. Also the Corps must operate these plants in consonance with the availability of water. Monthly operations are reported internally in the Corps on the Summary reports which have already been discussed. Also, the Corps maintains each project and makes such capital additions to the power installations as necessary.

FPC activities. FPC activities are primarily regulatory. In that capacity FPC reviews and approves (or disapproves) rate changes proposed by SPA, and other agencies marketing power from Corps projects. FPC has commented on SPA policies and practices, but apparently has no power to force changes in SPA. Postconstruction FPC contact with the Corps is apparently limited to the Form 1 report submitted by the Corps each year.

Summary. The main points concerning SPA operations are summarized as follows.

- SPA sells firm power to preference customers at low rates.
- SPA buys power to supplement the output of Corps projects which produce essentially peaking power and are actually operated as peaking plants.
- Unfavorable contract clauses have resulted in low power revenues.

. Supplemental charges by SPA have offset the adverse effects of the unfavorable clauses, but the legality of some of the supplemental charges has yet to be resolved by the courts.

. Running accounts are kept on each project with power to keep track of the recovery of costs allocated to power.

CHANGES WITH TIME.

Introduction. The Flood Control Act of 1944 is now more than thirty years old and the economic relationships that prevailed in the decades following the Act have changed. This section examines these factors briefly as they relate to the study of Arkansas River power projects.

Price indexes. Table 5 was extracted from the IWR report, 75 R1, July 1975, entitled: "Hydropower Potential at Corps of Engineers Projects" where it appeared as table V-2. The table was modified by deleting the third to the last and last columns and substituting columns entitled "March 1975" and "Percent change, 1970-March 1975."

The table demonstrates the recent general escalation of prices with which we are all acquainted. Most notable is the very large increase in the price of fuels of all kinds. These increases are being reflected in the increase in the cost of electrical power, which is also demonstrated in the table 5.

Table 5

Selected Price Trends - 1950-1975

(1967=100)

	1950	1960	1970	1973	March 1975	Percent Change 1950-1970	Percent Change 1970-March 1975
Consumer Price Index	72.1	88.7	116.3	133.1	157.8	61.3	35.7
Wholesale Price Index							
All commodities	81.8	94.9	110.4	134.7	170.4	35.0	54.3
Coal	83.3	95.6	150.0	218.1	388.3	80.1	158.9
Gas Fuels	NA	87.2	103.3	126.7	188.1	NA	82.1
Refined Petroleum Products	85.1	95.5	101.1	128.7	242.3	18.8	139.7
Electric Power	NA	101.2	104.8	129.3	191.1	NA	82.3
Electrical Machinery & Equipment	68.9	99.5	106.4	112.4	139.1	54.4	30.7

Source: 1950, 1960, 1970, Statistical Abstract, 1971,
1973, March 1975 Survey of Current Business, April 1975.

Value of power. Changes in the value of power can be demonstrated most readily by citing the values furnished by FPC and used in the various project studies in the Southwestern Division, Corps of Engineers and arranging them in chronological order. This is done in table 6.

Table 6. Summary of power values from FPC based on private financing, 1945-1975.

Price Level	Project	Power values: Dependable Capacity dollars/kw	Power values: Energy Mills/kwh	Interest rate percent	Fuel for Alternative plant
1945	Arkansas River	13.30	1.13		
1953	Tenkiller Ferry and Fort Gibson	19.90	1.15		
1963	Dardanelle	20.50	2.0		
1-64	Ozark	16.00	1.9		
1964	Eufaula	17.00	1.9		
1965	Dardanelle	20.00	2.1		
1-65	Dardanelle	17.50	2.1		
1966	Robert S. Kerr	16.50	1.9		
1966	Webbers Falls	16.50	1.9		
1968	Keystone	18.50	1.9		
7-73	Tennessee Colony	42.40	2.4		
1-74	Ft. Gibson #5 & 6	48.30	5.9	8.75	Coal
		83.60	1.6	8.75	Nuclear
2-74	Wolf Bayou	43.40	5.7	8.75	Coal
		13.70	17.4	8.75	Turbine
		77.70	1.6	8.75	Nuclear
2-74	Norfork	40.30	5.6	8.75	Coal
		13.70	16.9	8.75	Turbine
		71.70	1.5	8.75	Nuclear
2-74	Denison #3	45.90	4.1	8.75	Coal & Lignite
		82.40	1.5	8.75	Nuclear
7-74	Fort Gibson	63.50	6.4		Coal
7-74	Norfork	58.50	5.7		Coal
7-74	Denison	62.50	4.7		Coal
7-74	Kaw	62.00	6.3		Coal
12-74	Fort Gibson #4 & 5	67.50	6.4	8.75	
12-74	Denison #3	67.70	6.4	8.75	
12-74	Kaw	66.00	6.4	8.75	
1-75	Bell Foley	89.30	11.0	10.00	Coal(1)
	Bell Foley	90.60	1.6	10.00	Nuclear(2)
	Bell Foley	12.80	29.0	10.00	Turbine(3)
1-75	Wolf Bayou	94.50	10.0	10.00	Coal(1)
	Wolf Bayou	100.00	1.6	10.00	Nuclear(2)
	Wolf Bayou	25.00	25.0	10.00	Turbine(3)
1-75	Norfork	91.80	16.6	10.00	Coal(1)
	Norfork	90.30	1.6	10.00	Nuclear(2)
	Norfork	18.40	52.0	10.00	Turbine(3)

(1) Power factor (P.F.) = 55%
(2) P.F. = 65%
(3) P.F. = 7.5%

Project power revenues. Net generation and gross power revenues of the Corps power projects considered in this report are compared in table 7. The values are for fiscal years 1970 through 1974 during which sharp increases in prices were experienced as illustrated in table 6 and discussed in the previous paragraph. The gross revenues as shown on the following table show a contrary trend. This trend is emphasized in the tabulation below, which was developed by summing for each year the gross revenues of those projects, in table 7, that operated during each of five fiscal years.

Fiscal year	Gross revenues of 5 selected projects
1970	$5,938,000
1971	7,109,000
1972	6,381,000
1973	5,707,000
1974	5,697,000

This table also shows other trends that run counter to expectations. The most striking is the $0.52/kwh derived for the revenue per kwh for the first part year of operation of the Ozark project. This is in extreme contrast with the revenue per kwh for the first year of operation of Webbers Falls where the value is 0.79 mills. There are many cases where increased generation is accompanied by declining revenues as indicated in this table. The most extreme case occurred in FY's 1972 and 1973 at the Tenkiller Ferry project when generation increased from 79,644,000 kwh to 198,093,000 while revenues dropped from $596,000 to $537,000. The revenue per kwh dropped from 7.48 mills per kwh to 2.71 mills per kwh, by a factor of 2.76.

TABLE 7

NET GENERATION VS. GROSS REVENUES

Project	FY	Net Generation 1000 KWH	Gross Revenues $1000	Revenue Per KWH, Mills/KWH	Ave. Rev. Per KWH, Mills/KWH
Dardanelle	70	674,712	2,178	3.22	
	71	571,480	2,452	4.29	
	72	511,296	2,330	4.56	
	73	668,737	1,925	2.88	
	74	845,020	2,045	2.42	3.34
Ozark	73	143	74	517.48	3.93
	74	156,166	614	3.93	
Robert S. Kerr	72	368,202	434	1.18	
	73	652,017	1,725	2.65	
	74	850,280	1,702	2.00	2.06
Webbers Falls	74	272,962	217	0.79	0.79
Eufaula	70	174,192	1,446	8.30	
	71	205,581	1,629	7.92	
	72	214,596	1,464	6.82	
	73	383,817	1,255	3.27	
	74	347,739	1,272	3.66	5.33
Keystone	70	222,855	1,121	5.03	
	71	120,833	1,254	10.38	
	72	138,553	1,212	8.75	
	73	308,796	1,004	3.25	
	74	447,276	1,027	2.30	4.54
Tenkiller Ferry	70	101,924	598	5.87	
	71	140,141	628	4.48	
	72	79,644	596	7.48	
	73	198,293	537	2.71	
	74	189,528	530	2.80	4.07
Fort Gibson	70	244,690	855	3.49	
	71	213,463	919	4.31	
	72	173,724	929	5.35	
	73	328,043	864	2.63	
	74	360,241	823	2.28	3.33

A partial explanation for the foregoing is that much of increased generation made possible by the increased flows of 1973 and 1974 probably was marketed as low cost secondary or "dump" energy. The full range of reasons probably include the method used by the Corps to allocate revenues, and the activities of the marketing agency, SPA, which are beyond the scope of this report.

Project revenues, as discussed in the previous paragraph, are accounted for solely for the purpose of ascertaining whether the cost allocated to power at each project is being recovered as required by Section 5 of the Flood Control Act of 1945. Project power benefits, a separate concept and the subject of this paragraph, were estimated at various study stages prior to project construction to assure that the value of hydropower (as measured by the cost of producing an equivalent amount of power by the most likely alternate means)as previously discussed, was greater than the cost of producing it. Table 8 compares various estimates of average annual power benefits accruing during the fiscal years 1972 and 1974, using actual fiscal year energy generation amounts. The year 1972 was selected because it was the last year of record during which generation was low. The fact that the Ozark and Webbers Falls projects were not operating during 1972 is accounted for in the table. The year 1974 was selected because (a) it was a good water year (though not as good as 1973), (b) it was the latest year studied, and (c) all eight plants were in operation, (except Ozark where one unit in five was out of operation for 4 months).

TABLE 8

Estimates of Power Benefits, Arkansas River System, (using unit benefits, prevailing at various times)

	Period under study		
	Est. ave. year (1)	1972(2)	1974(3)
Dependable capacity, 1000 kw	631	465	624
Energy, 1,000,000 kwh	2,563	1,487	3,468
	Annual benefits in $1,000,000		
Benefits based on 1945 unit benefits			
Capacity @ $13.30/kw/yr	$ 8.39	$6.18	$ 8.30
Energy @ 1.13 mills/kwh	2.90	1.68	3.92
Total	$11.29	$7.86	$12.22
Benefits, based on unit benefits used in cost allocation studies.			
Capacity @ $16.00 to $19.90/kw/yr	$10.88	$ 8.19	$10.77
Energy @ 1.15 to 2.1 mills/kwh	4.76	2.73	6.35
Total	$15.64	$10.92	$17.12
Benefits based on January 1975 unit benefits using a coal fired alternate steam plant.			
Capacity @ $92.00/kw/yr	$58.05	$42.78	$ 57.41
Energy @ 12.5 mills/kw	32.04	18.59	43.35
Total	$90.09	$61.37	$100.76
Benefit, Jan. 75 unit benefits using a turbine driven alternate generating plant, and a coal fired base load plant.			
Capacity @ $18.75/kw/yr.	$11.83	$ 8.72	$11.70
Energy, 657 kwh/kw @25 mills/kwh	10.35	7.63	10.25
Energy, rest @ 12.5 mills/kwh	26.86	14.76	38.23
Total	$49.04	$31.11	$60.18
Benefits, Jan 75 unit benefits using a turbine driven alternative generating plant and a nuclear base load plant.			
Capacity @ $18.75/kw/yr.	$11.83	$ 8.72	$11.70
Energy, 657 kwh/kw @ 25 mills/kwh	10.35	7.63	10.25
Energy, rest @ 1.6 mills/kwh	3.44	1.89	4.89
Total	$25.62	$18.24	$26.84
Gross revenues (4)		$ 6.38	$ 5.70

(1) All eight plants in operation
(2) Six plants in full operation
(3) Seven plants in full operation and one plant in essentially full operation
(4) Allocated to the eight projects studied

In computing power benefits, unit power benefits representing values which prevailed during three time periods were selected. These are (a) 1946 unit benefits used in the basic Arkansas River project authorizing document, (b) the values used in the cost allocations where price levels ranged from 1956 to 1968, and (c) January 1975 price levels for which unit power benefits are shown in table 6 of this report. The 1975 unit power benefit values were taken as the average of the three 1975 values as given on Table 6. Alternative plants for 1975 were considered in several ways. First, the alternative power plant was assumed to be a coal fired steam plant, and benefits were computed accordingly. Since such a plant should operate at a power factor of about 55 percent, benefits were also computed on the basis that the alternative plant was powered by turbines which should operate at a power factor of 7.5 percent. To care for the low power factor, hydropower plant dependable capacity was assumed to operate 657 hours a year (7.5 percent of the time) with a benefit of 25.0 mills per kilowatt-hour. This is the lowest of the turbine energy values given on Table 6. The rest of the hydropower energy was assumed to replace either coal fired thermal energy at 12.5 mills per kilowatt hour, or nuclear plant energy at 1.6 mills per kilowatt hour.

Dependable capacity was considered to be the amounts used in the cost allocation studies. In Table 8, the fact that Ozark and Webbers Falls were not in operation in 1972 is accounted for by using zero dependable capacity

for these projects, for this year. Also, the 1974 dependable capacity for Ozark was discounted to account for the fact that one of the five units did not operate for four months.

Table 8 shows that 1972 power benefits were less than benefits based on estimated average year generation regardless of the unit benefits used. This rises from the fact that only 6 of 8 projects were on line, and that water was very short that year. Benefits in 1974 were greater than benefits based on average year generation because of favorable flow conditions. As expected, the power benefit for each of the periods examined increased as the date of the unit power benefits progressed to the latest one, January 1975. Power benefits were revised occasionally after 1946 until 1965 when Congress froze unit power benefits to the values now used on the "Power Project Data" sheet. These values are shown on Table 2, and are slightly higher than the unit benefits used in the cost allocation studies and in the preparation of Table 8. Benefits computed on the bases of January 1975 price levels and a coal fired alternative thermal plant show the highest annual benefit, about $90 million based on average year generation at the 8 plants of this study. Considering the fact that monthly power factor has dipped as low as 5 and 7 percent at Keystone and Eufaula during the 5 years studied, it appeared that turbine driven power plants might be considered as logical alternatives. Table 8 shows that benefits based on turbine-driven alternatives are less than benefits based on a coal-fired alternative, but more than power benefit based on earlier unit power values. The magnitude

of the benefits based on turbine-driven alternatives at 1975 price levels depends strongly on the value given to the energy in excess of 657 kilowatt hours per kilowatt per year. This is based on a 7.5 percent plant factor for turbine plants. The 8-plant benefits are about $26 million a year on the average if excess energy is given a value of 1.6 mills per kwh as with a nuclear plant and an average of about $49 million a year if 12.5 mills per kwh is assigned to the excess energy as with a coal-fired thermal plant. The latter value seems the more appropriate one since excess hydro energy can be expected to displace the most expensive energy in the system. These benefit estimates based on 1975 values are all much larger than benefits based on 1946 unit benefits which amounted to an average of about $11 million. Revenues for 1972 and 1974 as shown near the bottom of Table 8 amounted to about $6 million, or about one-half of the average benefits based on the earliest unit power values.

It is concluded that the power benefits accruing to the eight Arkansas River power projects considered in this report are considerably greater than the revenues currently being credited to the projects.

Summary. The preceding paragraphs are summarized as follows:

. Prices have generally increased at a very rapid rate in recent years.

. The cost of electric power is also showing a rapid rate of increase during recent years.

. The value of power, in terms of most likely alternatives to hydropower, in the Corps Southwestern Division geographic area, has shown rapid rises in the recent years.

. The current value of electric power in the region is greater than the value credited to the Corps power projects considered in this report in their original economic justifications, and the values used in current reports.

. Recent generation, i.e., 1973 and 1974, has been at higher rates than originally estimated, and power benefits have exceeded the previously estimated average annual benefits.

. Annual power revenues seem to be trending downward slowly, contrary to all other price trends.

. Power revenues credited to individual projects display a number of irrationalities, e.g., power revenues decreased as output increased.

EFFECTS OF HYDROELECTRIC POWER

Introduction. Hydroelectric power is included as a function in many Corps multi-purpose projects because studies indicated that the projects could provide power that had a ready market and at a cost less than the least expensive alternatives. Section 5 of the Flood Control Act of 1944 added two more requirements; that is, the electric power must be sold essentially at cost, but funds expended in producing power must be recovered within a reasonable period. Since the passage of the 1944 Act, the economic climate of the United States has changed drastically. Dominant issues of today include the energy crisis, inflation, increasing national debt, and increasing taxes. The effects of the hydroelectric power generated at the Corps plants under study are discussed below in the light of the foregoing.

Savings in Fossil Fuels. The hydroelectric power projects under study are located in an area in which gas and oil are often used to generate power. Coal and lignite are available, but these resources only recently are being used to generate electricity. It is felt that the energy generated at these power projects displaced energy which would otherwise have been generated using coal, gas, or oil resources. On this basis, Table 9 was developed to show how much of a nonrenewable resource each project saved through FY 1974; and on the average, how much fuel each project would save annually. Through FY 1974, these eight Corps projects saved almost eight million tons of coal, nearly 30 million barrels of oil, or 180 billion cubic feet of gas. The average annual saving amounts to more than a million tons of coal, more than four million barrels of oil, or about 26 billion cubic feet of gas.

TABLE 9

SAVINGS IN FOSSIL FUELS

Project	Generation Thru FY 74 10^6 KWH	Fuel Equivalent	Ave. Annual Generation 10^6 KWH	Fuel Equivalent
Dardanelle	5,284		613	
Coal, Million Tons		2.41		.28
Oil, Million Barrels		9.71		1.07
Gas, Billion Cu. Ft.		55.20		6.40
Ozark	156		429	
Coal, Million Tons		.07		.20
Oil, Million Barrels		.27		.75
Gas, Trillion Cu. Ft.		1.60		4.50
Robert S. Kerr	1,870		459	
Coal, Million Tons		.85		.21
Oil, Million Barrels		3.26		.80
Gas, Trillion Cu. Ft.		19.50		4.80
Webbers Falls	273		213	
Coal, Million Tons		.12		.10
Oil, Million Barrels		.48		.37
Gas, Trillion Cu. Ft.		2.80		2.20
Eufaula	2,081		260.3	
Coal, Million Tons		.95		.12
Oil, Million Barrels		3.62		.45
Gas, Trillion Cu. Ft.		21.70		2.70
Keystone	1,548		228	
Coal, Million Tons		.70		.10
Oil, Million Barrels		2.70		.40
Gas, Trillion Cu. Ft.		16.20		2.40
Tenkiller Ferry	2,026		114.5	
Coal, Million Tons		.92		.05
Oil, Million Barrels		3.53		.20
Gas, Trillion Cu. Ft.		21.20		1.20
Fort Gibson	3,899		190	
Coal, Million Tons		1.78		.09
Oil, Million Barrels		6.79		.33
Gas, Trillion Cu. Ft.		40.70		2.00

Economic. The economic circumstances which led to the inclusion of section 5 in the Flood Control Act of 1944, i.e., sell hydropower from public projects at the lowest possible rate to encourage the widespread use of electricity, have changed to the extent that conservation of energy is now the official policy of the government.

The difference between the current economic value of hydropower and the price a consumer pays for it may be considered the benefit that is accruing to the public. The amount of these current benefits is unknown since the current economic value of hydropower is not known. In fact, a substantial amount of research may be necessary to establish a rational method for determining the current economic value. The beneficial effects presumably extend to all customers of SPA who are spread over the entire SPA service area. The consumers vary from single family units, to major companies, and to the electric utilities themselves.

In including section 5 in the Flood Control Act of 1944, Congress obviously intended the use of hydropower produced at government projects to foster regional and national economic development. This policy on the generation and sale of hydropower was limited by the requirement that all costs of generating and distributing the power be recovered in a reasonable period of time. Although SPA insists that the cost of the first power project will be recovered in 50 years, the progress to this time has been very poor.

It has been suggested that the Corps of Engineers might contribute to the relief of the energy crisis by adding hydropower facilities to certain of their proejcts. Some arguments made to counter this suggestion include: (a) such new power must be turned over to SPA (Section 5, Flood Control Act of 1944), and they in turn must sell it at the lowest possible rate (same section, same act), (b) encouraging the use of electric power by selling it below cost may be against current national policy. Thus selling electric power below cost would only serve to continue our use of limited natural resources in an inefficient manner.

Social. To this point of this report, we have examined the revenues realized by the US Government from the sales of hydroelectric power from certain Corps hydropower plants and the current unit values of electric power and energy. The unit revenues received for the power and energy have been quite small when compared to their current values. This amounts to a burden on the government, which is balanced by a benefit received by the users of the low cost power and energy. Just how much benefit the ultimate users realize depends on how much of the low cost is passed on to them. This benefit is social as well as economic under our current economic and social system of values. The full effects of providing low cost electrical power and energy for use by industrial, commercial and residential customers, in both rural and urban areas, may never be known. Howevever, when lower costs of producing goods and services provided to the general public allow these savings to be passed along to general consumer, then this benefit accrues to the

general public. When costs of producing goods and services provided to the general public allow these savings to be kept by the power companies, by industries, by commercial and retail establishments, then this benefit accrues to this less widespread segment. To the extent that these savings from the use of low cost electrical energy result in increased employment within the power marketing region, the region and the nation benefits, additionally.

Environmental. The hydropower generated at all hydroelectric power projects, including those studied in this report have the obvious environmental benefit in that the atmospheric pollution of the alternative thermo-electric power plants is avoided. Also avoided to a small extent is the disturbance of land areas accompanying the extraction of fossil fuels from the earth, and the storage of ash as from coal burning plants. Also avoided is the accumulation of radioactive wastes that would occur with a nuclear alternative plant, and, in some cases, thermal pollution. Provision of a hydroelectric plant changes the environment of the stream on which it is located. The dam, which is provided with each hydroelectric plant and which serves other purposes in addition to generation of hydropower, changes the stream above the dam into a lake. Downstream from the dam the original channel may be superficially unchanged, except that extreme low flows may be increased, and the large flows tend to be diminished. The operation of hydropower plants on peak loads further modifies the pattern of natural flow. In this type of operation, the hydropower plants release water at a high rate for

a short period, and during the remainder of the day, they release no water. The result is a surge of water immediately below the dam which diminishes as the surge progresses downstream. In addition, the releases from the powerhouses tend to be colder than the natural flows at the site. The environmental changes have value in the sense that they provide for added recreation, hunting, fishing, and areas which can be used as wildlife refuges.

The changed stream and lake environment has permitted the introduction of new species to the region such as striped bass, walleyes, and rainbow trout to further enhance the stream and lake for fishing and recreation. The entire multiple-purpose project, of which power production is one purpose, has a number of areas devoted to recreation, hunting, fishing, and wildlife refuge purposes.

SUMMARY AND CONCLUSIONS

This report may be summarized as follows:

- The Southwestern Power Administration (SPA), organized in response to the Flood Control Act of 1944, markets the power from eight projects examined in this report and from other Corps projects.
- SPA's primary contracts are for the sale of more than is produced at the Corps projects.
- SPA buys additional thermal power to supplement the output of the hydroelectric projects when needed.
- The combined output is an increased amount of firm power which is sold to preference customers.

. In addition SPA contracts provide for the sale of peaking power, excess energy, emergency service, and interruptible capacity.

. SPA's operations have been reviewed on numerous occasions because of recurring deficits.

. GAO identified the main reasons for SPA's deficit as (a) excessive and inequitable credits to customers, (b) sale of power to support a defense industry, and (c) SPA's purchase of off-season power which it was unable to market.

SPA has attempted to institute rate adjustments to recoup losses.

. Rate adjustments have not been entirely successful because law suits have delayed their adoption.

. The rate adjustments that have been adopted and the increased water available during recent years have improved the financial status of SPA.

. Further rate adjustments would further improve their financial status, and might convince critics that such adjustments will enable them to fulfill the requirements of the law to "recover costs within a reasonable period."

. SPA, being created in response to section 5 of the Flood Control Act of 1944, must follow the requirements of the law, i.e., to sell the power at a low rate to encourage its widespread use.

. The ultimate remedy could be the revision of the requirements of the law.

. It is not readily apparent how the legal requirements might be changed.

. During recent years, inflation has caused the price of all goods and services, including electricity, to increase substantially.

. Further studies will be needed to develop the rationale for establishing new unit power benefits which reflect current cost trends and other factors.

. Presently, it appears that hydropower might be evaluated as low load factor peaking power to match the manner in which the units are operated.

. Energy in excess of the low load factor peaking power might be evaluated in terms of the cost of the fossil fuel consumption it displaces at conventional thermal plants.

. Using current unit power values would increase the values now presented as "power benefits" on the "Power Projects Data" sheets.

. The years of low energy generation during the early 1970's was the result of low stream flows in the region.

. Increased stream flow was experienced during 1973, 1974 and 1975, and energy generation increased to levels higher than the originally estimated average annual energy generation.

. Most of the eight hydroplants examined do not have records long enough to determine with certainty whether the original estimates of average annual energy generation were reasonably accurate.

. The records of the Fort Gibson and Tenkiller Ferry projects are the longest of the group. Examination of their records indicates that the original estimates of average energy generation were quite good.

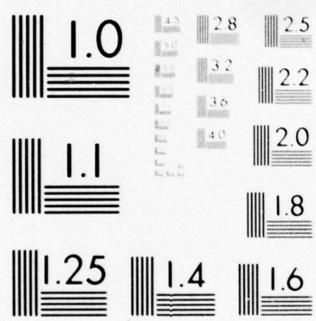
. A limited period was used to examine the dependable capacities of the eight projects of this report. This examination indicated the possibility of inconsistencies among the values now used for project dependable capacity.

AD-A054 148 INSTITUTE FOR WATER RESOURCES (ARMY) FORT BELVOIR VA F/G 10/2
MCCLELLAN-KERR ARKANSAS RIVER NAVIGATION SYSTEM. HYDROELECTRIC --ETC(U)
DEC 77

UNCLASSIFIED IWR-RR-77-R4 NL

2 OF 2
AD
A054148

END
DATE
FILMED
6-78
DDC



MICROCOPY RESOLUTION TEST CHART

NATIONAL BUREAU OF STANDARDS 1963 A

- The study reported herein is too limited in scope to evaluate completely the performance of the Corps hydropower projects, and how performance compares with preconstruction estimates.
- Expanded studies could indicate that the values now used for project dependable capacity and average annual energy require revision.
- Expanded studies, if undertaken, should consider all Corps projects in the SPA system and the purchased power used to firm up the hydroproject output, that is, the composition of the system should be the same as used in the AWR study of operating guide curves for power production, expanded to include subsequent power project additions to the system.
- The value of electrical power from projects considered as measured by the current cost of producing an equivalent amount of power has also increased substantially.

McClellan-Kerr Arkansas River

Navigation System

HYDROELECTRIC POWER GENERATION

(Supplement)

A Report Submitted to the:
U.S. Army Engineer Institute for Water Resources
Kingman Building
Fort Belvoir, Virginia 22206

by the
U.S. Army Engineer Division, Southwestern
Dallas, Texas 75202

February 1977

Table of Contents

TABLES

ILLUSTRATIONS

SUPPLEMENT
to
HYDROELECTRIC POWER GENERATION
at
McClellan-Kerr Arkansas River Navigation System

INTRODUCTION

This report supplements information presented in the report dated 1976, and entitled, "Hydroelectric Power Generation at the McClellan-Kerr Arkansas River Navigation System," prepared by the Corps of Engineers, Southwestern Division (SWD). This supplement presents the results of the method now used by SWD to keep running accounts for each power project to check its financial progress toward meeting the requirement of Section 5 of the Flood Control Act of 1944 that costs allocated to power be recovered in a reasonable period of time. This supplement also considers other potential methods for keeping the running power project accounts.

SPA FURNISHED INFORMATION

The Southwestern Power Administration (SPA) collects revenues from the sale of power from Corps hydropower projects, pays its obligations from these revenues and each year deposits the remainder in the Treasury of the United States as required by Section 5 of the Flood Control Act of 1944, SPA informs SWD of the amount deposited.

SWD RUNNING ACCOUNTS

In SWD each power-project account is kept in terms of "investment," that is, the first cost allocated to power plus interest during construction allocated by power. As capital additions are made to each power project, their cost is added to the investment account.

The original "investment" allocated to power is understood to have been computed by applying the percentage of the investment allocated to power derived in the original cost-allocation study to the more accurately determined total project investment computed to the date the project started operating. It is not known precisely how this was done, since minor differences become apparent in attempts to correlate information.

Accounts are kept on each power project to show the amounts spent on operation and maintenance. To this is added "Depreciation and amoritization charged to operation," and "Interest charged to operation" to determine the costs chargeable to power incurred during the year under consideration. This is modified as appropriate by "Other net gains or losses charged to power."

It was explained above that every year, SPA informs the Corps how much revenue they return to the Treasury Department from power generated at Corps projects. This sum represents the revenues realized from the sale of power and is applicable, as a gross sum, to all the Corps projects in the SPA system. From this sum ($22,467,611 for FY 1974) the Corps deducted the total O&M expense for all power project ($6,115,136 for FY 1974). The remainder ($16,352,475 in FY 1974) was apportioned to each power project in the ratio that the power investment in the project bears to the total power investment in Corps projects. For example, Dardanelle's power investment of $45,414,499 was 8.94 percent of the $508,027,246 (1974 investment) in SPA Corps power plants, so 8.94 percent of the remaining $16,352,475 or $1,461,911 was allotted to Dardanelle in addition to the $582,637 O&M expense for a total of $2,044,548. From this total is deducted $189,904 for depreciation and amortization, $975,767 for interest charged to operation, and $576,748 (value adjusted from $582,637) for operation and maintenance. To the result is added $931 for "other

net gain or losses," leaving $303,060 as the "results from operation" for FY 1974. From FY 1965 through FY 1973, the accumulated "results of operations" for Dardanelle amounted to $1,879,132. Addition of the previously mentioned sum, makes the accumulated results from operations through FY 1974 $2,182,192. Only when the accumulated value reaches the investment amount carried in the books will the project be paid out. At the end of FY 1974, the investment in Dardanelle amounted to $45,557,814, leaving $43,375,622 yet to be recovered.

The year by year progress of the accumulated "results of operations" for the Corps projects is shown in Table 1. The table shows abrupt changes from 1966 to 1967. This results from an adjustment to account for a change in the way depreciation was computed. It is interesting to note that after decades of operation, Tenkiller Ferry and Fort Gibson are still deeply in debt. At the end of FY 1974, the accumulated result of operations for the navigation project power installations amounted to a minus $6.2 million. The corresponding investment, at that time, amounted to $254.4 million. Only when the accumulated results from operations equal the total project investment in power will the projects meet the requirement of Section 5 of the Flood Control Act of 1944 that power investments be recovered.

TABLE 1

ACCUMULATED RESULTS OF OPERATIONS

Accumulated Results of Operations, $1 Million

Year	Dardanelle	Ozark	Robert S.Kerr	Webbers Falls	Eufaula	Keystone	Tenkiller Ferry	Fort Gibson	Total
1951									
1952								-0.3	-0.3
1953							-0.1	-0.5	-0.6
1954							-0.5	-1.0	-1.5
1955							-1.0	-1.7	-2.7
1956							-1.5	-2.5	-4.0
1957							-2.1	-3.4	-5.5
1958							-2.4	-3.8	-6.2
1959							-2.8	-4.4	-7.2
1960							-3.2	-4.9	-8.1
1961							-3.6	-5.5	-9.1
1962							-3.9	-6.0	-9.9
1963							-4.3	-6.5	-10.8
1964							-4.7	-7.1	-11.8
1965	-0.1				-1.0		-5.0	-7.6	-13.7
1966	-0.6				-1.3		-5.1	-7.9	-14.9
1967	-0.3				-0.8		-3.6	-5.4	-10.1
1968	-0.5				-0.7	-0.1	-3.7	-5.5	-10.5
1969	+0.3				-0.2	+0.2	-3.6	-5.4	-8.7
1970	+0.3				+0.5	+0.4	-3.7	-5.5	-8.8
1971	+1.3				+0.7	+0.9	-3.5	-5.3	-4.7
1972	+1.7	-0.2	-0.8		+1.0	+1.0	-3.5	-5.4	-6.2
1973	+1.9	-0.8	-0.7		+1.2	+1.2	-3.5	-5.3	-6.0
1974	+2.2	-1.0	-0.5	-0.5	+1.3	+1.3	-3.6	-5.4	-6.2
Project Investment at End of FY74	45.6	48.7	42.2	28.0	34.3	26.8	12.0	16.8	$254.4

In connection with the information annually supplied on the gross revenues from the sale of power, it is understood that SPA would like to perform the allocation to individual projects, a function now performed by the Corps as described above. It is understood that if SPA were allowed to perform this function, it would write off the newer projects first, that is, the ones with the higher interest rates. This would minimize the amounts to be paid for interest, and increase the amount available for other projects. The Corps opposes this method on the basis that the projects should be paid off individually in an orderly manner, i.e., in the chronological order that the projects were placed in service. SPA, on the other hand, indicates that the only requirement is that all costs allocated to power be recovered within 50 years after the last project is added to the system.

OTHER ACCOUNTING PROCEDURES

The poor financial status of the 20 plus year old Tenkiller Ferry and Fort Gibson projects as indicated in Table 1 led to examining the method now used at SWD to apportion revenues among the hydropower projects in the SPA system. Two operations define this present method. First, the total cost of operating and maintaining all hydropower plants in the SPA system is deducted from the revenues reported by SPA. Second, the remaining revenues are apportioned to each project in proportion to the project cost allocated to power. The sum of the project O&M cost and the apportioned amount is the amount credited to each project each year. Neither the history nor motives behind the adoption of these operations are known; however, exceptions can be taken on the basis of logic and the need to appraise project performance as realistically and accurately as possible. For example, the process of crediting each project with an amount equal to its operation and maintenance cost plus a portion of the total revenue less total operation and maintenance cost appears suspect. This procedure tends to spread extraordinary expenses to all projects in the system, a factor which may have some merit. However, the procedure also tends to hide extraordinary expenses at a project and to improve the apparent financial performance of a poorly performing project. In the same way, a good project appears worse than it really is. Also, apportioning revenues in proportion to "cost allocated to power" favors projects with relatively high cost power installations with no regard to the amount of the economic goods that are produced. This procedure tends to improve the appearance of poor projects and to degrade the appearance of good projects.

In view of the foregoing, modified accounting systems were applied to the Bull Shoals and Fort Gibson projects. The former was selected because the allocated cost of the power facilities ($60.0 million) was greater than at any other hydropower project in the SPA system, and because its 1975 financial standing (at minus $11.9 million) was the worst of all the SPA system projects. Fort Gibson was selected because of its poor standing (minus $5.5 million) and its relatively long service. The basic data for the modified accounting systems were derived from the SWD running accounts for each hydropower project. The projects considered are listed below:

Beaver Dam
Blakely Mountain Dam
Broken Bow Dam
Bull Shoals Dam
*Dardanelle Dam
DeGray Dam
Denison Dam
*Eufaula Dam
*Fort Gibson Dam
Greers Ferry Dam
*Keystone Dam
Narrows Dam
*Ozark Dam
*Robert S. Kerr Dam
Sam Rayburn Dam
Stockton Dam
Table Rock Dam
*Tenkiller Ferry Dam
*Webbers Falls Dam
Whitney Dam

*In the Arkansas River Navigation project.

For each project and each year of operation, values were determined for (a) apportioned power revenues, (b) operation and maintenance cost, (c) results of operations at the year end, and (d) total costs during year. Total revenues for each year were determined by adding the revenues apportioned to projects in operation during the year.

Columns 2 of Tables 2 (Bull Shoals) and 3 (Fort Gibson) are reproduced from the SWD running accounts. Columns 3 represent and attempt to reproduce the SWD accounting from the derived data. The differences that are apparent indicate the SWD process has not been reproduced faithfully. The differences are considered small enough so that trends are not obscured.

Columns 4 in Tables 2 and 3 represent a trial accounting system in which SPA-reported revenues were apportioned to each project in proportion to the cost allocated to power in the project. The step in the presently used system of first deducting total O&M costs from gross revenues prior to apportioning was eliminated on the basis that the result would depict the financial performance of each project more accurately. Table 2 shows that this approach improves the 1975 status of Bull Shoals from minus $11.9 million now in SWD accounts to minus $5.7 million. Table 3 shows that the status of Fort Gibson was impaired, the corresponding values being minus $5.5 million and minus $7.2 million. These changes are felt to reflect the relative financial efficiencies of the two hydropower plants.

TABLE 2

Financial Standing At Year's End Using
Various Methods For Allocation Revenues
To Corps Projects In SPA System
BULL SHOALS PROJECT
1953-1975

ALL VALUES ARE GIVEN IN MILLIONS OF DOLLARS

Years	Values From SWD records (1)	Test Allocation using SWD assumptions (1)	Revenues Allocated by project cost allocated to power (first trial accounting) (2)	Revenues allocated by power benefits (second trial accounting) (3)
1953	.0	.3	.4	.5
1954	-.7	-.3	-.1	.2
1955	-2.3	-1.9	-1.4	-1.0
1956	-4.1	-3.5	-1.9	-2.2
1957	-6.0	-5.4	-3.5	-3.7
1958	-7.4	-6.8	-4.6	-4.5
1959	-8.8	-8.3	-5.9	-5.7
1960	-10.4	-9.9	-7.2	-6.8
1961	-12.0	-11.5	-8.5	-7.9
1962	-13.5	-13.0	-9.7	-8.8
1963	-15.4	-14.9	-11.3	-10.0
1964	-17.6	-17.0	-13.1	-11.6
1965	-19.2	-18.6	-14.4	-12.4
1966 (4)	-13.0	-12.6	-8.2	-5.5
1967	-13.5	-13.3	-8.6	-5.1
1968	-13.4	-13.5	-8.5	-4.1
1969	-12.7	-13.0	-7.8	-2.2
1970	-12.4	-12.9	-7.5	-0.8
1971	-11.9	-12.3	-6.7	1.2
1972	-11.6	-12.2	-6.5	2.5
1973	-11.7	-12.5	-6.3	3.3
1974	-11.6	-12.7	-6.2	4.4
1975	-11.9	-13.2	-5.7	5.0

(1) Each project is allocated annually O&M cost plus a portion of total revenues less total O&M cost. This remainder is apportioned to each porject in proportion to the cost allocated to power at the project.

(2) Total revenues are apportioned to each project in proportion to the project cost allocated to power.

(3) Total revenues are apportioned to each project in proportion to the power benefits credited to the project.

(4) An ajustment was made in 1966 to account for a change in the way depreciation was computed.

TABLE 3

Financial Standing At Year's End Using
Various Methods For Allocating Revenues
To Corps Projects In SPA System
FORT GIBSON PROJECT 1951-75

Years	Values from SWD records (1)	Test allocation using SWD assumptions (1)	Revenues allocated by project cost allocated to power (First trial accounting) (2)	Revenues allocated by power benefits (Second trial accounting) (3)
	ALL VALUES ARE GIVEN IN MILLION OF DOLLARS			
1951	.0	-.1	-.1	-.1
1952	-.3	-.1	.0	-.1
1953	-.5	-.3	-.3	-.4
1954	-1.0	-.9	-.9	-1.0
1955	-1.7	-1.6	-1.6	-1.8
1956	-2.5	-2.3	-2.3	-2.6
1957	-3.3	-3.1	-3.1	-3.4
1958	-3.8	-3.7	-3.8	-4.0
1959	-4.4	-4.3	-4.2	-4.6
1960	-4.9	-4.9	-4.9	-5.3
1961	-5.5	-5.5	-5.5	-6.0
1962	-6.0	-6.0	-6.1	-6.6
1963	-6.5	-6.4	-6.6	-7.2
1964	-7.1	-6.9	-7.5	-7.8
1965	-7.6	-7.4	-8.0	-8.4
1966 (4)	-5.2	-5.1	-5.8	-6.3
1967	-5.4	-5.3	-6.2	-6.7
1968	-5.5	-5.4	-6.3	-6.9
1969	-5.4	-5.4	-6.3	-6.9
1970	-5.4	-5.4	-6.3	-7.0
1971	-5.3	-5.3	-6.3	-7.1
1972	-5.4	-5.4	-6.5	-7.5
1973	-5.3	-5.5	-6.7	-7.8
1974	-5.4	-5.6	-6.9	-8.0
1975	-5.5	-5.7	-7.2	-8.3

(1) Each project is allocated annually O&M cost plus a portion of total revenues less total O&M costs. This remainder is apportioned to each project in proportion to the cost allocated to power at the project.

(2) Total revenues are apportioned to each project in proportion to the project cost allocated to power.

(3) Total revenues are aportioned to each project in proportion to power benefits credited to the project.

(4) An adjustment was made in 1966 to account for a change in the way depreciation was computed.

A second test allocation is shown in the last columns of Tables 2 and 3. In this allocation, the SPA-reported revenues were apportioned to each project in proportion to project power benefits computed on the basis of arbitrarily selected unit power benefits. These are the 1945 values used in the Arkansas River report of $13.30 per year per kilowatt of dependable capacity, and 1.13 mills per kilowatt hour of average annual energy. This aspect of the method requires additional careful consideration if this line of thought is pursued further. Table 2 shows that the status of Bull Shoals is further improved to $5.0 million while Table 3 shows that the status of Fort Gibson has declined further to minus $8.3 million. Table 4 lists for the hydropower projects in the SPA system the following: (a) cost allocated to power, (b) 1975 financial status from SWD records where it is identified as accumulated results from operation, and (c) 1975 financial status according to the second trial accounting. The fact that the totals of the last two columns differ indicate difficulties in the arithmetic. The trends in the table are, however, felt to be valid, and that the results of the second trial accounting appear to represent prevailing conditions more accurately than do the values taken from SWD records. The presently used accounting procedure tends to show poor projects in a more favorable light and good projects in a light less favorable than actually exists.

TABLE 4

FINANCIAL STATUS AT END OF F Y 1975
OF HYDRO POWER PROJECTS IN SPA SYSTEM
SWD RECORDS COMPARED WITH STUDY RESULTS

Projects	Cost of power (2)	F Y Financial Status (1) SWD records (3)	Study result (4)
	ALL VALUES IN MILLIONS OF DOLLARS		
Beaver Dam	33.9	2.0	1.4
Blakely Mountain Dam	25.1	-3.7	-8.2
Broken Bow Dam	23.8	-.1	.7
Bull Shoals Dam	60.0	-11.9	5.0
Dardanelle Dam	45.4	2.0	1.7
DeGray Dam	22.7	-.1	-.6
Denison Dam	20.7	-4.3	-9.7
Eufaula Dam	34.3	1.3	.3
Fort Gibson Dam	16.8	-5.5	-8.3
Greers Ferry Dam	34.1	1.3	-2.8
Keystone Dam	26.8	1.2	1.4
Narrows Dam	7.4	-1.4	-4.6
Norfork Dam	13.8	-2.5	-2.5
Ozark Dam	47.2	-1.2	-.8
Robert S. Kerr Dam	42.2	-.7	.3
Sam Rayburn Dam	23.7	-.3	-2.3
Stockton Dam	25.1	.4	.1
Table Rock Dam	53.9	-1.9	3.7
Tenkiller Ferry Dam	12.0	-3.7	-5.7
Webbers Falls Dam	27.3	-.9	-.2
Whitney Dam	8.3	-.1	-3.1
Total	604.5	-30.1	-34.2

(1) Financial status must attain value in "Cost of Power" column before requirements of Section 5, F.C. Act 1944 are filled.

(2) Project cost allocated to power.

(3) Total revenues less total O&M cost are apportioned to projects in proportion to the project cost allocated to power.

(4) Total revenues apportioned to project in proportion to the annual power benefit of the project.

POWER PROJECT DATA

The Corps prepares "Power Project Data Sheets" once a year in accordance with regulations. Those for Dardanelle Lock and Dam are furnished as a sample. Sheet 4 of the data sheets includes a summary of "Power Production, Revenues, and O&M Costs." The last two columns indicate that accumulated gross revenues were $17,524,529 and the accumulated amount for interest and amortization was $12,777,099 at the end of FY 1974. Although no inconsistency exists, to the uninformed person, this presents a much more favorable picture than that depicted in Table 1 in which the accumulated results from operations at the end of FY 1974 amount to $2.2 million ($2,182,192) as compared to an investment in power of $45,557,814. These data sheets are furnished to the SPA, to the FPC Regional Office in Fort Worth, and to the Office, Chief of Engineers, Washington D.C.

FPC FORM NO. 1

General Guidance is provided in ER-37-2-11, 16 May 1971, for the preparation of the Annual Report to the Federal Power Commission, FPC Form No. 1 (RCS FPC 1002). The report originates in the districts, goes through the divisions to reach the Office, Chief of Engineers, by 1 September after the end of the fiscal year. A copy is furnished the marketing agency (SPA in this case) at the same time. The accounting is consistent with the SWD running accounts, but is much more detailed. The very poor financial standing of the Corps power projects is apparent in these reports, but it is apparent only after much detailed examination by knowledgeable people. Furthermore, these reports are not widely distributed.

Power Project Data Sheet
DARDANELLE LOCK AND DAM

Date: 26 November 1974
District: Little Rock, Ark.
Sheet No. 1 of 5

LOCATION: Mile 205.5, Arkansas River, Arkansas; approximately 2 miles northwest of Dardanelle, Arkansas.

AUTHORIZATION: Public Law 525, 79th Congress, 2d session, approved 24 July 1946, in accordance with recommendations in H. D. 758.

PURPOSES: Navigation and power.

STATUS: In operation; installed capacity, 124,000 kw.

STORAGE CAPACITY

Purpose	Elevations (Ft., m.s.l.)	Storage Capacity (Acre-Feet)	Gross Heads for Power (Ft.)
Power pondage	336 - 338	65,000	Maximum 49
Inactive and dead	336	421,000	Minimum 19
TOTAL		486,000	Average 48

Power Project Data Sheet
DARDANELLE LOCK AND DAM
(continued)

Date: 26 November 1974
District: Little Rock, Ark.
Sheet No. 2 of 5

POWER DATA	Initial Installation	Ultimate Installation
Number and capacity (kw.) of units	Four 31,000	Four 31,000
Total capacity, kw.	124,000	124,000
Dependable capacity, kw.	(1)114,000	124,000
Primary energy, annual, kw.-hr.	(1)170,000,000	(2)193,000,000
Total energy, average annual, kw.-hr.	613,000,000	(3)613,000,000
Basis for determining capacity and energy available: (Critical hydro period: August 1955 through January 1957)	Dardanelle operating in an integrated system with Pensacola, Markham Ferry, Fort Gibson, Tenkiller Ferry, Eufaula, Robert S. Kerr, Ozark, and Denison	Dardanelle operating in an integrated system with Pensacola, Markham Ferry, Fort Gibson, Tenkiller Ferry, Eufaula, Robert S. Kerr, Ozark, and Denison

Effect on power at and by other plants:

Plant	Initial Installation: Primary Energy Annual (Kw.-hr.)	Initial Installation: Depend. Cap. (Kw.)	Initial Installation: Total Energy, Avg. Annual (Kw.-hr.)	Ultimate Installation: Primary Energy Annual (Kw.-hr.)	Ultimate Installation: Depend. Cap. (Kw.)	Ultimate Installation: Total Energy, Avg. Annual (Kw.-hr.)
Effect on power at downstream projects:						
	None	None	None	None	None	None
Effect on power by upstream projects:						
Tenkiller Ferry	(Undetermined)	0	(Undetermined)	(Undetermined)	0	(Undetermined)
Eufaula	(Undetermined)	0	(Undetermined)	(Undetermined)	0	(Undetermined)

(Footnotes on sheet 5)

Power Project Data Sheet
DARDANELLE LOCK AND DAM
(continued)

Date: 26 November 1974
District: Little Rock, Ark.
Sheet No. 3 of 5

ANNUAL BENEFITS (Dollars)	Initial Installation	Ultimate Installation
Navigation	(4)2,117,500	(Same as initial installation)
Power:		
Capacity: 124,000 kw. at $20.50	2,542,000	
Energy: 613,000,000 kw.-hr. at 2.00 mills	1,226,000	
(Alternate source $115/kw., 1963 price level)		
TOTAL	5,885,500	

ANNUAL CHARGES (Dollars)	Initial Installation	Ultimate Installation
Interest on investment - 2½% (86,551,100 x 0.025)	2,163,800	(Same as initial installation)
Amortization of investment - 100 yrs. (86,551,100 x 0.002312)	200,100	
Operation and maintenance	1,160,000	
Major replacements	73,000	
TOTAL	3,596,900	

Power Project Data Sheet
DARDANELLE LOCK AND DAM
(continued)

Date: 26 November 1974
District: Little Rock, Ark.
Sheet No. 4 of 5

FUNDS BY FISCAL YEARS (Dollars)	Navigation and Power	Recreation	Total
Allotted to 30 June 1974	82,300,000	2,189,800	84,489,800
Allowance for FY 1975	0	254,000	254,000
Scheduled Funds			
FY 1976	0	166,000	166,000
FY 1977	0	0	0
FY 1978	0	0	0
FY 1979	0	0	0
FY 1980	0	0	0
FY 1981	0	0	0
TOTAL	82,300,000	2,609,800	84,909,800
Additional reqd to complete ultimate installation	0	4,116,200	4,116,200
TOTAL	82,300,000	6,726,000	89,026,000

In-Service Dates	
Closure	Oct 1964
Available for flood control	-
Available for navigation	Dec 1969
Available for water supply	-
In-service dates for power:	
31,000 kw. - May 1965	
31,000 kw. - Jun 1965	
31,000 kw. - Oct 1965	
31,000 kw. - Feb 1966	

POWER PRODUCTION, REVENUES, AND O&M COSTS

Fiscal Year	Net Generation (Kw.-hr.)	O&M Expenses (Dollars)	Gross Revenues (Dollars)	Amount for Interest on Investment and Amortization (Dollars)
FY 1965-69	2,012,903,700	1,879,984	6,626,900	4,746,916
FY 1970	674,711,900	527,682	1,918,461	1,390,779
FY 1971	571,479,700	641,595	2,789,443	2,147,848
FY 1972	511,295,700	610,098	2,179,514	1,569,416
FY 1973	668,736,800	511,323	1,965,663	1,454,340
FY 1974	845,019,800	576,748	2,044,548	1,467,800
TOTAL	5,284,147,600	4,747,430	17,524,529	12,777,099

Power Project Data Sheet
DARDANELLE LOCK AND DAM
(continued)

Date: 26 November 1974
District: Little Rock, Ark.
Sheet No. 5 of 5

REMARKS:

(1) Reduced dependable capacity and primary energy are due to reduced head conditions at time of closure. Primary energy is computed without water losses for navigation lockages.

(2) Primary energy with allowance for navigation requirements.

(3) Average annual energy same as shown for initial installation. Reduction due to navigation not yet determined.

(4) Average annual navigation benefits for the Arkansas River would accrue only to the plan of development in its entirety. For cost allocation purposes only, part of the benefits of a "navigation only" plan has been assigned to the Dardanelle Reservoir in the same proportion as the annual charges of a reservoir for navigation only bears to the annual charges of navigation only plan for the Arkansas River.

SUMMARY

. SPA returns to the Treasury the funds received from the sale of hydropower from Corps projects serving the SPA system less funds required to defray SPA expenses.

. SPA informs SWD of the amount returned to the Treasury.

. SWD apportions the total revenues reported by SPA less total O&M projects to each hydropower project in proportion to the cost allocated to power in the project. Each project is then credited the sum of its O&M cost and the apportioned amount.

. Using these values, SWD maintains a running fiscal year accounting of the financial status of each hydropower project.

. Such an accounting is required to determine whether the requirement of Section 5 of the Flook Control Act of 1944 (ie., that funds expended on power facilities be covered in a reasonable time) will be met.

. A summary of the SWD accounting presents a very gloomy financial picture.

. A similar gloomy picture appears in the FPC annual report which is not widely distributed.

. The more widely distributed "Power Project Data Sheets" do not present the gloomy side of the picture.

. The SWD accounting pictured the two oldest hydropower projects of the Arkansas River project (Fort Gibson and Tenkiller Projects) as being deeply in debt.

. The SWD system was examined to determine whether the old projects were penalized in some way.

. The assumption that total O&M costs be deducted from revenues before the remainder is apportioned among projects appeared suspect, since the greater the project O&M costs, the more credit the project would receive to hide poor project performance.

. Also suspect is the assumption that revenues be apportioned in proportion to the project cost allocated to power. This places emphasis in the wrong place, that is, cost rather than on economic results.

. An approximate trial accounting was undertaken in which revenues were apportioned in proportion to benefits computed arbitrarily on the basis of 1945 values of $13.30 per kilowatt of dependable capacity per year and 1.13 mills per kilowatt hour of average annual energy.

. The specific benefit values to be used in an accounting system require much additional study.

. The trial accounting system presented in this report is felt to be superior to the one now in use in that it distributes power revenues in proportion to the economic output of each project, and does not assure payment of O and M costs regardless of how exorbitant they may be.

. The trial accounting shows Bull Shoals in FY 1975 to be $5.0 million on the way toward recovering its $60.0 million investement in power while the corresponding SWD value is minus $11.9 million. The former value is felt to represent more nearly the true economic value of Bull Shoals.

. The trial accounting lessens the 1975 financial status of the Fort Gibson project to minus $8.3 million from minus $5.5 million in the SWD records. This, too, is felt to reflect the relative economic value of

this project.

. It is felt that the SWD accounting system should be changed to one similar to the second trial accounting system described herein. The result should represent reality more closely and make the records a more useful planning and managerial tool.

U.S. Army Engineer Division, Southwestern.
McClellan-Kerr Arkansas River navigation system ; hydroelectric power generation / U.S. Army Engineer Division, Southwestern. -- Ft. Belvoir, Va. : U.S. Army Engineer Institute for Water Resources ; Springfield, Va. : available from National Technical Information Service, 1977.
110 p. : ill. (IWR Research report ; no. 77-R4
1. Hydroelectric power generation. 2. Water resources development - Economic aspects. 3. Arkansas River. I. Title. II. Series: U.S. Institute for Water Resources. IWR Research report no. 77-R4

HD1694 .A42 U584r no. 77-R4

☆ U.S. GOVERNMENT PRINTING OFFICE : 1978—734-633